# COLLINSVILLE SOLAR THERMAL PROJECT

## ENERGY ECONOMICS AND DISPATCH FORECASTING

Draft Report


The University of Queensland Australia

Global Change Institute


Prepared for

RATCH-Australia Corporation

RATCH-Australia Corporation

## Chief Investigators

Paul Meredith, Global Change Institute
Craig Froome, Global Change Institute
Hal Gurgenci, Queensland Geothermal Energy Centre of Excellence
John Foster, School of Economics
Tapan Saha, School of Information Technology and Electrical Engineering

## Authors

William Paul Bell, p.bell2@uq.edu.au, Energy Economics and Management Group
Phillip Wild, p.wild@uq.edu.au, Energy Economics and Management Group
John Foster, j.foster@uq.edu.au, Energy Economics and Management Group

## Energy Economics and Management Group

| | |
|---|---|
| Postal address: | School of Economics<br>The University of Queensland<br>St Lucia, Brisbane QLD 4072, Australia |
| Phone: | +61 7 3346 0594 or +61 7 3365 6780 |
| Fax: | +61 7 3365 7299 |
| Website: | http://www.uq.edu.au/eemg/ |

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## Preface

This is a draft report and the final report is due for publication November 2014. This combined Energy Economics and Dispatch Forecasting report is one of seven reports evaluating the feasibility of a hybrid gas-concentrated solar power (CSP) plant using Linear Fresnel Reflector (LFR) technology to replace the coal fired power station at Collinsville, Queensland, Australia. Table 1 shows the seven reports and the affiliation of the lead authors.

**Table 1: Collinsville feasibility study reports and their lead researcher groups and authors**

| Report | Affiliation of the lead author |
| --- | --- |
| Yield forecasting (Bell, Wild & Foster 2014b) | EEMG |
| *Dispatch forecasting (Bell, Wild & Foster 2014a) | EEMG |
| *Energy economics (Bell, Wild & Foster 2014a) | EEMG |
| Solar mirror cleaning requirements (Guan, Yu & Gurgenci 2014) | SMME |
| Optimisation of operational regime (Singh & Gurgenci 2014b) | SMME |
| Fossil fuel boiler integration (Singh & Gurgenci 2014a) | SMME |
| Power system stability assessment (Shah, Yan & Saha 2014a) | PESG |
| Yield analysis of a LFR based CSP by long-term historical data (Shah, Yan & Saha 2014b) | PESG |

*Combined report

These reports are part of a collaborative research agreement between RATCH Australia and the University of Queensland (UQ) funded by the Australian Renewable Energy Agency (ARENA) and administered by the Global Change Institute (GCI) at UQ. Three groups from different schools undertook the research: Energy Economics and Management Group (EEMG) from the School of Economics, a group from the School of Mechanical and Mining Engineering (SMME) and the Power and Energy Systems Group (PESG) from the School of Information Technology and Electrical Engineering (ITEE).

EEMG are the lead authors for three of the reports. Table 2 shows the “Collinsville Solar Thermal - Research Matrix” that was supplied by GCI to the researchers at EEMG for their reports. The suggested content for the three reports in the matrix was restructured to provide a more logical presentation for the reader that required combining the Energy Economics and Dispatch Forecasting reports.

**Table 2: Collinsville Solar Thermal - Research Matrix – EEMG's components**

| |
|---|
| **Yield Forecasting**<br>Modelling and analysis of the solar output in order that the financial feasibility of the plant may be determined using a long-term yield estimate together with the dispatch model and the modelled long-term spot price. |
| **Dispatch Forecasting**<br>Analysis of the expected dispatch of the plant at various times of day and various months would lead to better prediction of the output of the plant and would improve the ability to negotiate a satisfactory PPA for the electricity produced. Run value dispatch models (using pricing forecast to get $ values out). Output will inform decision about which hours the plant should run. |
| **Energy Economics**<br>Integration of the proposed system into the University of Queensland's Energy Economics Management Group's (EEMG) existing National Electricity Market (NEM) models to look at the interaction of the plant within the NEM to determine its effects on the power system considering the time of day and amount of power produced by the plant. Emphasis to be on future price forecasting. |

The results from this yield report (Bell, Wild & Foster 2014b) are used in the combined 'Energy economics and dispatch forecasting' report (Bell, Wild & Foster 2014a).

***Justification for combining the Energy Economics and Dispatch Forecasting reports***

The following paragraphs provide a detailed justification for combining the Energy Economics and Dispatch Forecasting reports. This justification can be skipped by most readers because the justification is most probably only of interest to ARENA and RATCH.

The matrix identifies improving the negotiation of a PPA as an important outcome of the project. This objective is paramount given the failure of many renewable energy projects stem from the failure to negotiate a suitable PPA. The negotiation of a PPA is required with a purchaser of the electricity before banks or other intermediary will provide finance for the project. The financiers also require profit calculations for the lifetime of the plant before financial approval is given, so the calculations are both essential to finalise the start of a project and to aid in negotiating a PPA.

The revenue calculation requires both the prices and dispatch. However, the 'Energy Economics Report' is to present prices and the 'Dispatch Forecasting Report' is to present dispatch and PPA. Whichever report the revenue calculations are placed, requires duplication between the reports. This duplication is unnecessary in a combined report. In addition, the same EEMG 'National Electricity Market (NEM)' model produces both prices and dispatch simultaneously, so it is more logical to discuss EEMG's model and its outputs: prices and dispatch, in the same report.

Furthermore, there is the failure of logic of presentation in the three-report format. The revenue is calculated from the prices and dispatch, so a logical presentation is to discuss the prices and dispatch first then introduce the revenue calculations. This is not feasible in the three-report format without duplication. Therefore, both clarity of exposition and removal of duplication arguments make amalgamation of the ‘Energy Economics’ and ‘Dispatch Forecasting’ reports sensible.

Doctor William Paul Bell
Research Fellow
Energy Economics and Management Group
The School of Economics
The University of Queensland

# Executive Summary

## 1 Introduction

This report primarily aims to provide both dispatch and wholesale spot price forecasts for the lifetime of the proposed hybrid gas-solar thermal plant at Collinsville. This report is the second of two reports and uses the findings of Bell, Wild and Foster (2014b) in the first report.

## 2 Literature review

The literature review discusses the ANEM model that is used to forecast wholesale spot prices from demand and supply forecasts.

The review introduces the concept of gross demand to supplement the Australian Electricity Market Operator's (AEMO) "total demand". This gross demand concept helps to explain the permanent transformation of the demand in the NEM region and the recent demand over forecasting by the AEMO. Factors causing the permanent transformation are discussed. The review also discusses the implications of the irregular ENSO cycle for demand and its role in over forecasting demand.

Forecasting supply requires assimilating the information in the *Electricity Statement of Opportunities* (ESO) (AEMO 2013a). AEMO expects a reserve surplus across the NEM beyond 2022-23, excepting a small reserve deficit in Queensland in 2020-21. However, there is a continuing decline in manufacturing, which is freeing up supply capacity elsewhere in the NEM. The combined effect of export LNG prices and declining total demand are hampering decisions to transform proposed gas generation investment into actual investment and hampering the role for gas as a bridging technology in the NEM. The review also estimates expect lower and upper bounds for domestic gas prices to determine the sensitivity of the NEM's wholesale spot prices and plant's revenue to gas prices.

The largest proposed investment in the NEM is from wind generation. However, the low demand to wind speed correlation is inducing wholesale spot price volatility. Economically viable energy storage is expected shortly beyond the planning horizon of the ESO in 2022-23. This viability is expected to not only defer investment in generation and transmission within the NEM but also accelerate the growth in off-market produced and consumed electricity within the NEM region.

### 2.1 Research questions

The report has the following overarching research questions:

> *What is the expected dispatch of the proposed plant's gas component given the plant's dispatch profile and expected LFR yield?*
>
> *What are the wholesale spots prices on the NEM given the plant's dispatch profile?*

The literature review refines the latter research question into four more specific research question ready for the methodology:

- *What are the wholesale spots prices on the NEM for a gas price of $8.50/GJ given the plant's dispatch profile?*
- *How sensitive are wholesale spot prices to a gas price change from $8.50/GJ to $11/GJ given the plant's dispatch profile?*
- *What is the plant's revenue for a gas price of $8.50/GJ given the plant's dispatch profile?*
- *How sensitive is the plant's revenue to gas price change from $8.50/GJ to $11/GJ given the plant's dispatch profile?*

# 3 Methodology

In the methodology section, we discuss forecasting the proposed plant's dispatch, the NEM's supply capacity, the process to produce a normalised TMY total demand and the ANEM model to calculate the wholesale spot prices from the supply capacity and total demand. These forecasts help address the research questions.

# 4 Results and analysis

In the results section we will present the findings for each research question.

# 5 Discussion

We analyse the extent to which the research questions are informed by the results from the yield report.

# 6 Conclusion

In this report, we have identified the key research questions and established a methodology to address these questions. The models have been established allowing the calculation of the wholesale spot price, dispatch and revenue projections for the proposed plant at Collinsville.

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## Equations

# 1 Introduction

The primary aim of this report is to help negotiate a Power Purchase Agreement (PPA) for the proposed hybrid gas-LFR plant at Collinsville. The report's wider appeal is the techniques and methods used to model the NEM's demand and wholesale spot prices for the lifetime of the proposed plant.

To facilitate the PPA negotiations, this report produces the half-hourly dispatch of the plant's gas component and the associated half-hourly wholesale spot prices for the plant's node on National Electricity Market (NEM) given the yield from the plant's solar thermal component and a fixed total dispatch profile shown in Table 3. The total dispatch profile incorporates both gas and solar outputs and differs between weekdays and weekends.

**Table 3: Proposed plant's total dispatch profile by hour of week**

| Time | Dispatch (MW) |
|---|---|
| Weekdays: 8am-10pm | 30 |
| Weekdays: 7am-8am | ramp from 0 to 30 |
| Weekends | entire yield of the solar thermal component |

The half-hourly yield profile for the solar thermal component of the plant is determined by Bell, Wild and Foster (2014b) in a previous report. Three profiles are utilised to help to negotiate a PPA: solar thermal yield, gas dispatch and wholesale market spot price.

The executive summary provides an outline of the report.

# 2 Literature review

## 2.1 Introduction

This literature review helps us to develop the research question and inform the methodology to address the research question. This report uses two research questions to express the report's research requirements shown in Table 2.

> *What are the wholesale spots prices on the NEM given the plant's dispatch profile?*
>
> *What is the expected dispatch of the proposed plant's gas component given the plant's dispatch profile and expected LFR yield?*

The literature review informs the development of forecasts for the National Electricity Market (NEM) for the 30 year lifetime of the proposed new solar thermal plant from 1 April 2017 to 31 March 2047 (RAC 2013).

Section 1 discusses demand forecasting. Section 2 discusses supply forecasting. Section 3 discusses dispatch and wholesale spot price forecasting while developing supporting research questions to investigate the interaction of the proposed plant with the NEM. Section 3 also introduces the Australian National Electricity Market (ANEM) Model that this report uses to calculate the dispatch and wholesale spot prices from the demand and supply forecasts in Sections 2 and 3.

## 2.2 Forecasting demand in the NEM for the lifetime of the proposed plant

This section discusses forecasting demand for the lifetime of the proposed plant.

There has been an increase in demand for electricity for over two decades. However, more recently, the Australian Electricity Market Operator (AEMO) has produced a number of demand forecasts that have over projected demand and have missed the general declining demand for electricity. This section focuses on reasons for AEMO's over-forecasting to help inform this report's demand forecasting.

There are many countervailing trends in the demand for electricity. For instance, there is uneven population growth across Australia, which will affect demand unevenly. The growth in the uptake of air conditioners is nearing a plateau, which will reduce the rate of increase in electricity demand. The price for electricity has increased rapidly over the last 10 years, which may see people become sensitive to price, so a price elasticity of demand starts to slow the rate of increase in demand. There are education campaigns to make people aware of their electricity use, which will reduce the rate of increase. Additionally, there is the ongoing shift in the economy from manufacturing to services that is expected to reduce demand because manufacturing is the most energy intensive sector.

Section 1 discusses the short and long-term drivers for demand. Sections 2 to 6 discuss structural changes to electricity demand that cause a permanent decrease in total demand. Section 7 discusses the ENSO cycle that causes temporary changes in total demand. Section 8 discusses the AEMO's over-forecasting of electricity demand.

## 2.3 Short-run and long-run drivers for electricity demand

Yates and Mendis (2009, p. 111) consider short-run drivers for demand due to weather, for instance in the short-run people can turn on fans or air conditions to meet changes in weather conditions. Yates and Mendis (2009, p. 111) list the following short-run electricity demand drivers:

- weather – air temperature, wind speed, air humidity and radiation;
- indoor environmental factors – indoor air temperature, wind speed and humidity;
- time of the day;
- day of the week;
- holidays;
- seasons;
- durations of extreme heat days;
- urban heat island effects;
- utilisation of appliances;
- person's financial position; and
- personal factors – clothing, physical activity and acclimatisation.

This report uses demand profiles from the years 2007-12, which incorporate all these short-run drivers for demand. A typical meteorological year (TMY) demand profile is created using 12 typical meteorological months (TMMs) derived in the yield report. This process ensures consistency between the reports, so both demand profile and yield profiles have consistent weather conditions.

Yates and Mendis (2009, p. 112) consider the following long-run drivers for demand:

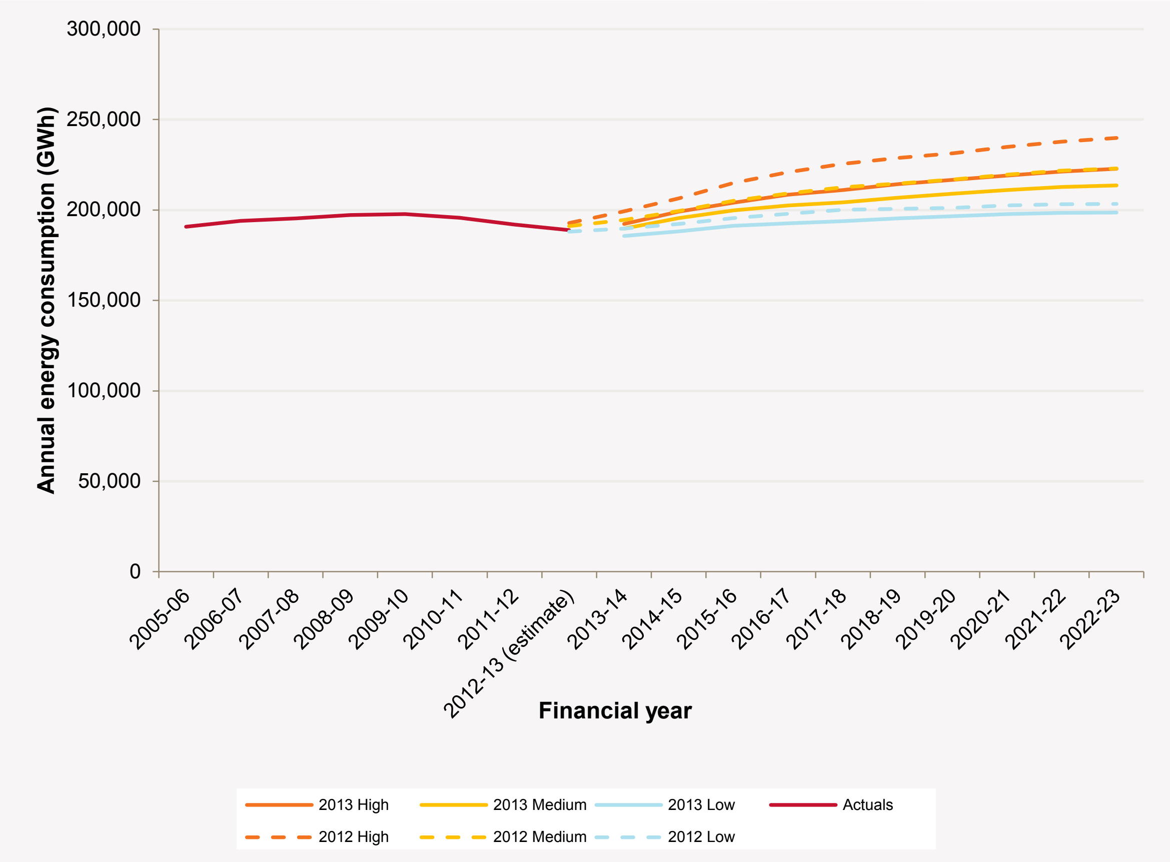
- climate change;
- population growth, composition and geographic distribution;
- real price of electricity;
- the price of electricity relative to the price of gas;
- economic growth;
- real income and employment status;
- interest rates;
- renewal of building stock;
- households and floor space per capita;
- previous years consumption; and
- commercial and industrial electricity use.

The AEMO's long-term forecasts incorporate these changes and so could be used to provide a growth rate for the TMY demand profile. However, the AEMO forecasts present two problems: consistently over-forecasting total demand in recent years and failure to cover the entire lifetime time of the proposed plant. Additionally, in the long run people can install solar PV, solar water heaters and more energy efficient appliances and build more energy efficient housing. These have the effect of transforming the shape of the demand profile. The next section discusses extending the definition of demand to account for these changes and the subsequent adjustment of the shape of the TMY demand profile.

### 2.3.1 Permanent transformation of demand: technological innovation redefining demand

Bell, Wild and Foster (2013) investigates the transformative effect of non-scheduled solar PV and wind turbine generation (WTG) on total electricity demand. The motivation for their study is a series of forecasts by the AEMO for increases in total demand in the NEM but there is a continuing reduction in total demand, see Figure 1.

**Figure 1: 2013 NEFR annual NEM energy forecast**




(Source: AEMO 2013a)

A number of factors contribute to these poor predictions, including: the Australian economy's continued switch from industrial to service sector, improvements in energy efficiency, the promotion of energy conservation, and mild weather induced by the la Nina phase of the ENSO cycle reducing the requirement for air conditioning. Sections 2.2.7 discuss the ENSO cycle in more detail. Additionally, there is growing non-scheduled generation that is meeting electricity demand.

However, the AEMO's "Total demand" definition fails to account for non-scheduled generation. AEMO (2012a, sec. 3.1.2) defines the "Total Demand" in the following way.

> *"Total Demand" is the underlying forecast demand at the Regional Reference Node (RRN) that is met by local scheduled and semi-scheduled generation and interconnector imports after excluding the demand of local scheduled loads and that allocated to interconnector losses.*
>
> *"Total Demand" is used for the regional price calculations in Dispatch, Pre-dispatch and Five-minute Pre-dispatch 5MPD, and to determine dispatch targets for generating units.*

Semi-scheduled wind farms are included in "Total Demand" but non-scheduled wind farms are excluded.

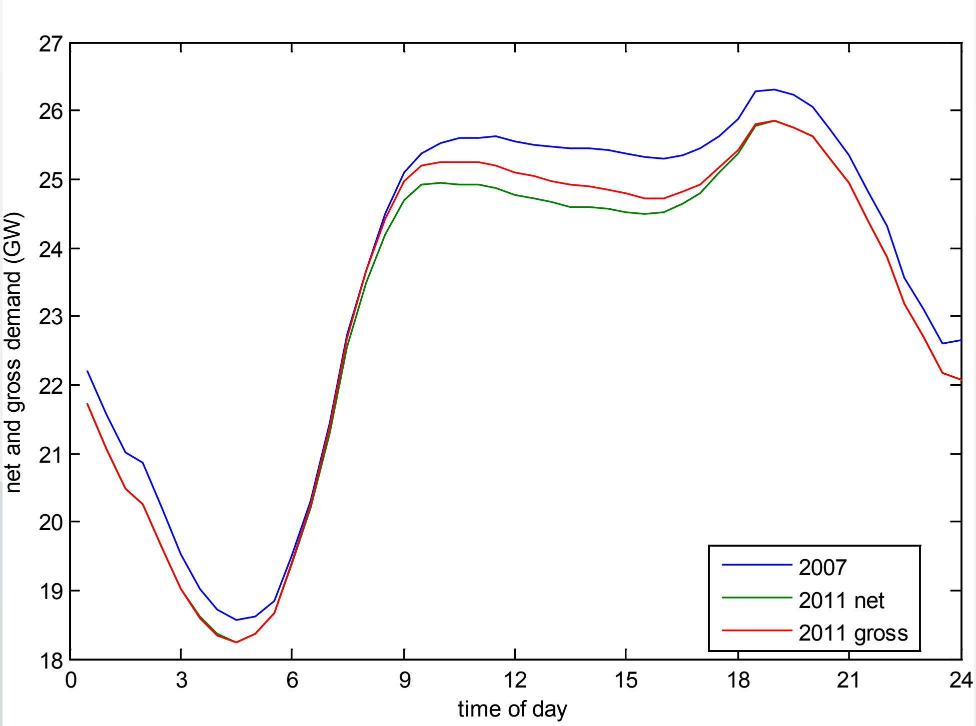
Bell, Wild and Foster (2013) introduce the concept of gross demand to incorporate non-scheduled generation. Equation 1 defines the term gross demand used in this report and relates the term to the AEMO's definition of "total" demand. Bell, Wild and Foster (2013) use the term "net demand" to describe AEMO's "total demand".

**Equation 1: Demand - gross, scheduled and non-scheduled**

gross demand = total demand + non-scheduled demand (this report)
gross demand = net demand + non-scheduled demand (Bell 2013)

In Figure 2, Bell, Wild and Foster (2013) compare the daily average net and gross demand for 2011 with 2007 The gross and net demand in 2007 is similar because the quantity of non-scheduled generation is relatively small, hence only one line is necessary to represent both. Figure 2 shows that the inclusion of non-scheduled solar PV and WTG accounts for a good portion of the decrease in net demand. The observation both helps explain the poor long-term forecasting performance of the electricity industry and requires the modelling of gross demand to consider the transformative effect on the net demand profiled over time. This report grosses up the net demand TMY derived from the years 2007-12 for their respective levels of non-scheduled generation before calibrating the TMY demand profile to a consistent December 2013 level of non-schedule generation.

**Figure 2: Comparing daily gross and net demand for 2007 & 2011**




(Source: Bell 2013)

Equation 1 could be extended to include solar hot water heating in the definition of gross demand because this extension would help explain the decrease in net demand from 2007 to 2011 in the early hours of the morning shown in Figure 2. The solar hot water heaters displaced electric hot waters heater that traditionally used the off peak electricity during the early hours of the morning. This concept of gross demand could also incorporate energy efficiency. However, the effect of solar hot water heating and energy efficiency on demand is left for further research.

The McKinsey Global Institute (MGI 2014) expects the cost of solar PV installations to continue to decrease. Further installation will further depress the midday depression in "total demand" (net demand) in Figure 2. However, MGI (2013) expects battery storage to become economically viable in 2025, perhaps even earlier given sudden innovations. This timing is well within the lifetime of the proposed plant. Battery storage in conjunction with non-scheduled generation allows further growth in gross demand with little or no growth in "total demand". Furthermore, the time shifting feature of battery storage is likely to moderate both the midday depression and the evening peak in total demand shown in Figure 2.

There are two consequences of the economic viability of battery storage for the proposed plant: no growth in total demand post 2025 and a transformation of the relative profitability of the LFR and gas components of the plant. The environment prior to battery storage provides relatively higher profitability for the gas component than the LFR and vice versa.

The AEMO (2014c) expects the capacity of the current generation fleet sufficient to meet any increase in total demand until after 2023, see Table 4, which is when battery storage is expected to allow growth in gross demand without an increase in total demand. The only exception is Queensland, which may have a reserve deficit in 2020-21. This is just short of the period when battery storage is expected to induce no growth in total demand that makes any new scheduled generation a very marginal proposition.

**Table 4: Regional reserve deficit timings**

| | Queensland | NSW | Victoria | SA | Tasmania |
|---|---|---|---|---|---|
| Reserve deficit timings | 2020-21 | Beyond 2022-23 | Beyond 2022-23 | Beyond 2022-23 | Beyond 2022-23 |

(Source: AEMO 2014c)

At least three factors could account for the AEMO projecting shorter reserve deficit timing for Queensland than the rest of the NEM: population growth, the production of liquefied natural gas (LNG) and other mining activity. Consistent with the AEMO's projection, Table 5 shows the most likely percent growth in population across the NEM from 2006 to 2030 where Queensland has a relatively high expected population growth compared to the rest of the NEM.

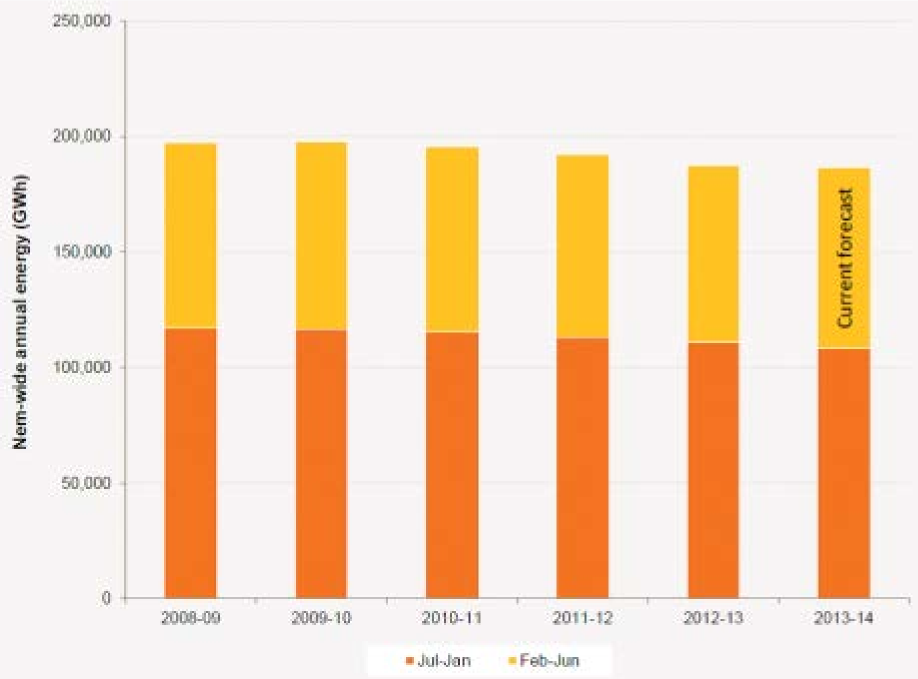
**Table 5: Projected population growth from 2006 to 2030 across the NEM**

| Series B | Qld | NSW | Vic | SA | Tas | ACT | NEM |
|---|---|---|---|---|---|---|---|
| **State** | 57% | 27% | 36% | 24% | 14% | 29% | 36% |
| **Capital city** | 57% | 32% | 41% | 25% | 22% | | 38% |
| **Balance of state** | 57% | 20% | 20% | 21% | 8% | | 32% |

(Source: ABS 2008)

However, Figure 2, in a quarterly update (AEMO 2014c) of the Statement of Opportunities (AEMO 2013a), shows the demand across the NEM continues to decrease. This literature review discusses reasons for the poor forecast further. For instance, Section 2.2.5 discusses energy efficiency and the switch to high density living that will reduce "total demand" per capita. Additionally, Section 2.2.3 discusses the production of liquefied natural gas in Queensland, the resources bubble and associated decline in manufacturing that will also reduce "total demand" per capita.

**Figure 3: Six-year comparison of energy consumption**

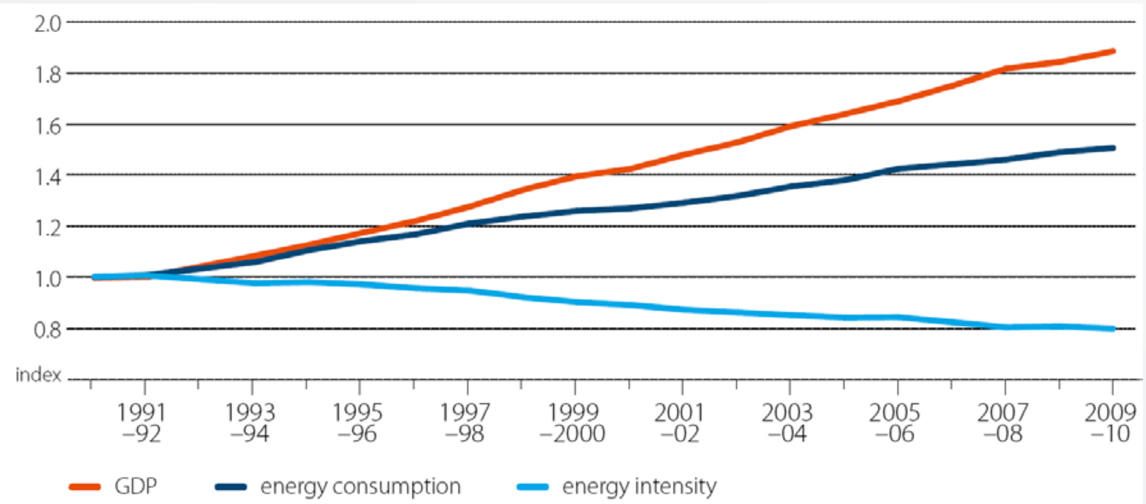



(AEMO 2014c)

### *2.3.2 Permanent transformation of demand: manufacturing decline*

Figure 4 shows that growth in energy consumption has remained below the growth in Gross Domestic Product (GDP) and energy-intensity has been declining. Energy-intensity is the ratio of energy used to activity in the Australian economy. Ball et al. (2011, p. 8) discuss how declining energy-intensity is a worldwide phenomenon.

**Figure 4 Intensity of Australian energy consumption**



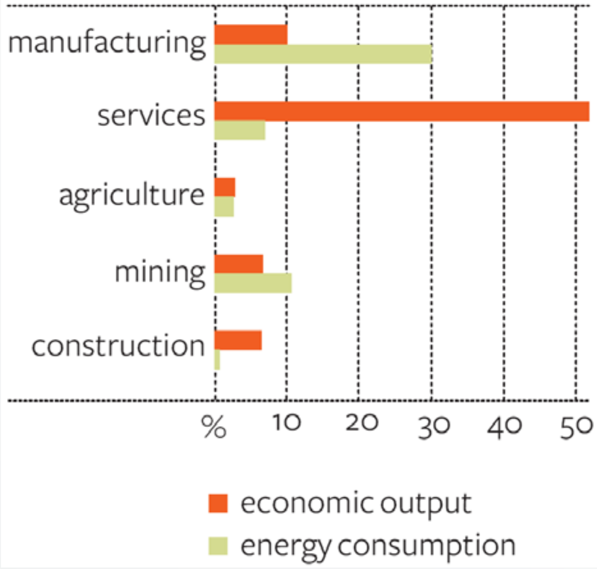
(Source: Schultz & Petchey 2011, p. 5)

Shultz and Petchey (2011, p. 5) consider the decline in energy-intensity due to two factors being:

- improvements in energy efficiency associated with technological advancement; and
- shift in industry structure toward less energy-intensive sectors.

The improvement in energy efficiency is likely to continue. Figure 5 compares the percentage share of economic output and of energy use for different industries. Manufacturing is the most energy intensive industry and the service industry is one of the least intensive industries. Mining is less energy intensive than manufacturing. Therefore, the increase in the size of both service and mining industries and decrease in the size of the manufacturing industry accounts for some of the decline in energy-intensity.

**Figure 5 Shares of energy consumption and economic output 2005-06**




(Source: Sandu & Syed 2008, p. 4)

There is a temporary increase in electricity demand from increased construction activity in Queensland to establish the infrastructure ensuing from the resources bubble and more specifically, to make the gas trains to liquefy natural gas (LNG) for export.

However, the decline in manufacturing is accelerated by the resources bubble via the exchange rate mechanism. The bubble causes Australia's exchange rate to appreciate. This appreciation makes Australia's manufactured exports relatively more expensive to buyers overseas and makes manufactured imports relatively less expensive to buyers in the domestic market. In addition, the gas price increases ensuing from the export of LNG will further accelerate the decline of the manufacturing sector and in turn reduce "total" demand for electricity.

The latest major manufacturing closures include:

- car manufacturing in SA, NSW and VIC
- Alcoa's smelter and roll mills in VIC and NSW

These manufacturing industries are unlikely to return after the collapse of the resources bubble because there are on-going moves toward more trade liberalisation. The consequence is a persistent reduction in "total demand". This manufacturing induced reduction in "total demand" is unevenly distributed across the NEM with NSW and VIC having the largest declines in absolute terms.

Sections 2.3.1 and 2.4.2 discuss further the consequences of the resources bubble and LNG export for the NEM and the proposed plant.

### 2.3.3 Permanent transformation of demand: smart meters

This section discusses how smart meters providing customers with dynamic pricing can help customers reduce demand for electricity at peak times and increase public engagement in energy conservation.

Smart meters allow retailers to collect high frequency data automatically on customers' electricity usage and customers to monitor their own use of electricity. Smith and Hargroves (2007) discusses the introduction of smart meters, the ensuing public engagement and the substantial reduction in peak demand being achieved. Currently in Australia, transmission and distribution investment is made to meet the peak demand period, usually between 3 pm and 6 pm in most 'Organisation for Economic Co-Operation and Development' (OECD) countries. Georgia Power and Gulf Power in Florida, USA, have installed smart meters resulting in Georgia Power's large customers reducing electricity demand by 20-30 per cent during peak times and Gulf Power achieving a 41 per cent reduction in load during peak times. Zoi (2005) reports on California's experience of tackling the growing demand for peak summer power using a deployment of smart meters with a voluntary option for real time metering that uses lower tariffs during off peak times and higher tariffs during peak times with a 'critical peak price' reserved for short periods when the electricity system is really stressed. Energy consumption during peak periods was reduced by 12-35 per cent. Most Californians now have lower electricity bills and 90 per cent of participants support the use of dynamic rates throughout the state.

Australia is slow in deploying smart meters, and Queensland particularly slow, but a deployment across the NEM within the lifetime of the proposed plant is a reasonable expectation.

### 2.3.4 Permanent transformation of demand: energy efficiency

Improvements in energy efficient are an ongoing process and expected to reduce "total" demand in NEM. These improvements have been hampered by a state based approach but during the lifetime of the plant more effective energy efficiency policy and deployment is expected.

Hepworth (2011) reports how AGL and Origin Energy called for a national scheme rather than state based schemes because compliance across the different states' legislations is costly. However the National Framework for Energy Efficiency (NFEE 2007) instituted by the Ministerial Council on Energy (MCE) claims significant progress. But in a submission to the NFEE (2007) consultation paper for stage 2, the National Generators Forum (NGF 2007) comments on the progress since stage 1 of the NFEE *"Progress in improving the efficiency of residential and commercial buildings can best be described as slow and uncoordinated, with a confusion of very mixed requirements at the various state levels. Activities in areas of trade and professional training and accreditation, finance sector and government have been largely invisible from a public perspective"*. The NGF (2007) states that the proposals for stage 2 are modest and lack coordination and national consistency. Therefore, there is disagreement between the MCE and participants in the NEM over coordination in the NEM.

The star rating of appliances by Equipment Energy Efficiency (E3 2011) is an example of a campaign that is visible and easy to understand, which is moot with some success and addresses information asymmetry. As discussed, the introduction of smart meters and flexible pricing has engaged customers in other countries. This public engagement by smart meters can provoke a much wider interest in the conservation of electricity to include energy efficiency. Both Origin Energy (2007) and NGF (2007) acknowledge that the MEPS established for refrigerators and freezers, electric water heaters and refrigerative air conditioners are effective and support the expansion of MEPS to include other appliances. An expansion of MEPS will further constrain growth in “total demand”.

In another submission to the consultation paper, Origin Energy (2007) calls for the NFEE to focus on non-price barriers to energy efficiency that the price signal from a carbon price is unable to address. Origin Energy considers the following items are suitable for direct action to remove non-price barriers:

- education/information campaigns;
- minimum Energy Performance Standards (MEPS);
- phasing out electric hot water systems;
- incandescent light bulb phase out; and
- building standards.

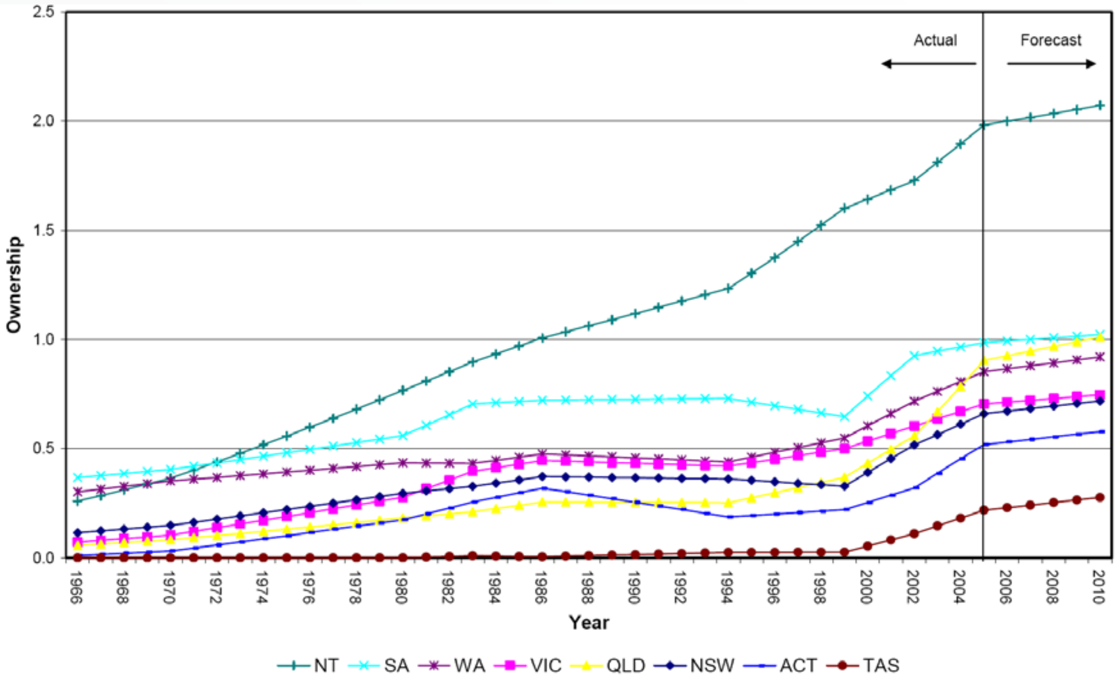
Stevens (2008, p. 28) identifies the need for raising public awareness of electricity demand and shaping public opinion to combat climate change but Origin Energy (2007) considers public education/information campaigns are considerably underfunded. Since 2008, there have been campaigns to improve peoples’ awareness of the relation between climate change and electricity use. This is expected to continue during the lifetime of the proposed plant and permanently affect people’s behaviour.

NGF (2007) states that water heating accounts for 30% of household electricity and 6% of total stationary energy use. Section 2.2.2 discusses how the installation of solar hot water systems maintains gross demand but permanently reduces “total” demand.

Both Origin Energy (2007) and NGF (2007) express concern about the phase out of incandescent light bulbs being in favour of the phase out but better consultation prior to the phase out may have prevented some adverse and unintended consequences, such as, the poor light rendition and high failure rate of substandard imported compact fluorescent lights (CFL), which caused some people to adopt halogen down lights that have higher energy use than incandescent light bulbs. However, the phasing out of incandescent bulbs has permanently reduced “total” demand.

The MEPS will reduce the amount of energy new air conditioners use and so reduce the demand for electricity. However, Figure 6 shows increases in ownership of air conditioners across all states, which will increase demand for electricity. There was a rapid growth in air conditioner ownership from 2000 to 2005 when the growth was expected to slow from 2006. The NT shows a considerably different trajectory to the other states but lies outside the NEM region.

**Figure 6: National Ownership of Air Conditioners by State**




(Source: NAEEEC 2006, p. 9)

The changes in building standards have engendered an improvement in new housing energy efficiency. Yates and Mendis (2009, p. 121) discuss how increased urban salinity and ground movement damage induced by climate change will accelerate building stock renewal, leading to a long-run reduction in demand for electricity. However, the projected growth in the number of households exceeds the projected growth in population, which means fewer people sharing a household and increasing electricity demand above population growth. Table 6 shows the projected growth in the number of households across the NEM from 2006 to 2030. Table 7 shows the projected growth in the number of households above the projected growth in population. Table 7 is the difference between Table 6 and Table 5.

**Table 6: Uneven projected household growth from 2006 to 2030 across the NEM**

| Series II | QLD | NSW | VIC | SA | TAS | ACT | NEM |
|---|---|---|---|---|---|---|---|
| State | 68% | 37% | 44% | 31% | 22% | 38% | 45% |
| Capital city | 66% | 40% | 50% | 31% | 28% | | 46% |
| Balance of state | 70% | 32% | 31% | 32% | 18% | | 43% |

(Source: ABS 2010)

**Table 7: Projected household growth above population growth from 2006 to 2030**

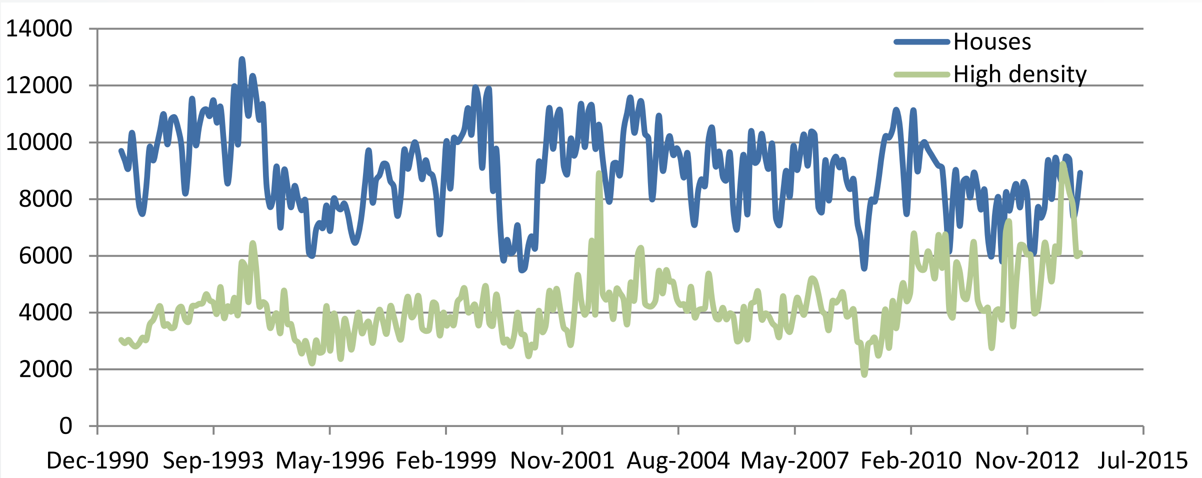
| Series II - Series B | QLD | NSW | VIC | SA | TAS | ACT | NEM |
|---|---|---|---|---|---|---|---|
| State | 11% | 10% | 8% | 7% | 8% | 9% | 9% |
| Capital city | 9% | 8% | 9% | 6% | 6% | | 8% |
| Balance of state | 13% | 12% | 11% | 11% | 10% | | 11% |

Series I, II and III household projections use the assumptions of the Series B population projection in Table 5. The household projection assumptions in Table 6 are those for Series II of the ABS (2010). Series II is considered the most likely growth scenario where Series I and III represent lower and higher growth scenarios, respectively.

While the number of people per house decreases, Building Research Advisory New Zealand (BRANZ Limited 2007, pp. 28-9) discusses how there is an increase in the size of the average house in Australia where the new standard house has four bedrooms and two bathrooms. The increases in size of house will increase demand for electricity. While house size has become larger, the section size has become smaller, which increases the heat islands effect that is the reduction in greenery around a suburb to moderate temperature swings. The heat island effect will also increase the demand for electricity. Nevertheless, the increase in the number of swimming pools acts to moderate the heat island effect.

However, since BRANZ Limited (2007, pp. 28-9) made their observations, there has been a distinct switch from individual houses to high-density living. Figure 7 shows the number of private residential approvals and compares house with high-density approval numbers. This switch to high-density living will act to reduce the average size of housing stock and moderate growth in total demand.

**Figure 7: Private residential approvals**




(Source: ABS 2014)

### *2.3.5 Permanent transformation of demand: price awareness*

Australia still enjoys relatively low electricity prices by international standards but the commodity boom has driven prices higher for fossil fuels, which has in turn driven electricity prices higher (Garnaut 2008, pp. 469-70). At low electricity prices people are insensitive to price rises but at higher prices, people become much more sensitive to price increases to the extent that people decrease their use of electricity. The higher price example means that the price elasticity of demand for electricity has increased or is more elastic. The price elasticity of demand is the percentage increase or decrease in quantity demanded in relation to the percentage increase or decrease in price. The higher prices for electricity could see a higher elasticity of demand operating, which would moderate further increases in demand for electricity.

In the past, the cost of electricity was so low to be considered "small change", so never attracted much attention. However, once an awareness of electricity use is developed, a demand hysteresis effect takes hold, so even if prices decrease the awareness of electricity use remains. This demand hysteresis produces a permanent modification of behaviour.

Additionally, the other permanent transformations of demand discussed in the previous sections act to solidify demand hysteresis.

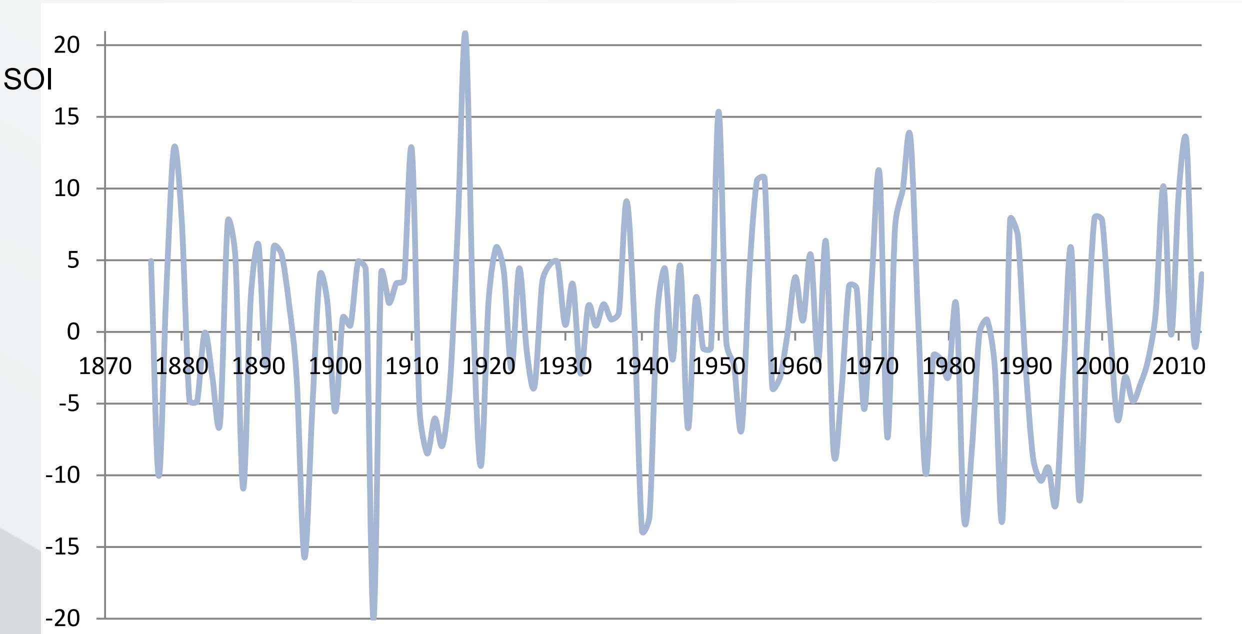
### 2.3.6 *Irregular cyclic transformation of demand: ENSO*

The yield report has already discussed the ENSO in detailed but a purely demand side interpretation informs the poor forecasting performance of the electricity industry. In the ENSO cycle, the *El Niño* phase relative to the *La Niña* phase increases solar intensity, temperature and pressure and reduces humidity. The overall *El Niño* effect is to increase both solar yield and electricity demand.

Figure 8 shows the mean annual southern oscillation index (SOI) for 1875-2013 where a positive SOI indicates a La Niña (BoM 2014b) bias and the negative SOI indicates an El Niño (BoM 2014a) bias.

The recent demand forecasts have overestimated demand during the *La Niña* bias period since 2007. In contrast, the prior period 1976 to 2007 has a strong *El Niño* bias. Forecasters who assume a continuing *El Niño* bias would over estimate demand.

**Figure 8: Mean annual SOI 1875-2013**




(Source: BoM 2014c)

### 2.3.7 *Over-forecasting bias and NSP profit correlation*

The profits of the NSPs are calculated on their capital expenditure, which encourages them to build more infrastructures. If peak demand increases, the NSPs are legally obliged to build more infrastructures to accommodate the demand and the NSPs profit from accommodating the demand. This remuneration process encourages NSP to provide demand forecasts that indicate increases in demand. The AEMO previously relied on the NSPs demand forecasts but the NSPs continual over forecasting of demand called into question their reliability. The AEMO now commissions independent forecasts but they are still over-forecasting “total” demand.

### 2.3.8 Demand Summary

This section introduced the concept of gross demand to inform the discussion of the numerous structural changes to demand that are permanently reducing the AEMO's "total" demand. The irregular ENSO cycle contrasts with the numerous permanent structural changes and may enter a high demand phase for a while before returning to a low demand phase.

The reserve deficit timing for Queensland 2020-21 has two main drivers: Queensland population growth and the resources bubble. In particular, there is the construction in developing gas trains and new coalmines and their supporting infrastructure. However, both the recent shift to high-density living and energy efficiency improvements will mute demand growth from the first driver. For the second driver, the higher export linked prices for gas and appreciated exchange rate induced by the resources bubble will accelerate the decline of Australian manufacturing and consequently reduce NEM wide "total demand".

This report assumes the current AEMO forecasts lack the consistent over-forecasting bias correlated to NSP profit motives but the massive permanent structural changes in demand makes demand forecasts based on previous trends fraught with problems, so this report assumes continued growth in gross demand but no growth in the AEMO's "total" demand.

## 2.4 Forecasting supply in the NEM for the lifetime of the proposed plant

This section discusses forecasting supply or generation capacity of the NEM for the lifetime of the proposed plant. There are four major factors influencing investment decision for new generation: “total” demand, climate change policy, fossil fuel prices and the decreasing costs of renewable generation. This section also discusses delivery of supply via the network shown in Section 8.

Table 4 discusses the regional reserve deficit timings where AEMO expects surplus capacity in the NEM beyond 2022-23. This is the period when battery storage is expected to become economically viable, which will in effect create further surplus generation because storage enables the continual utilisation of the cheapest forms of generation during off peak periods and use arbitrage to sell during peak periods. This process will initially compete directly with the more expensive forms of generation such as peak-gas generation, so making future investments in peak-gas generation risky.

### 2.4.1 Reserve deficit in Queensland and manufacturing decline

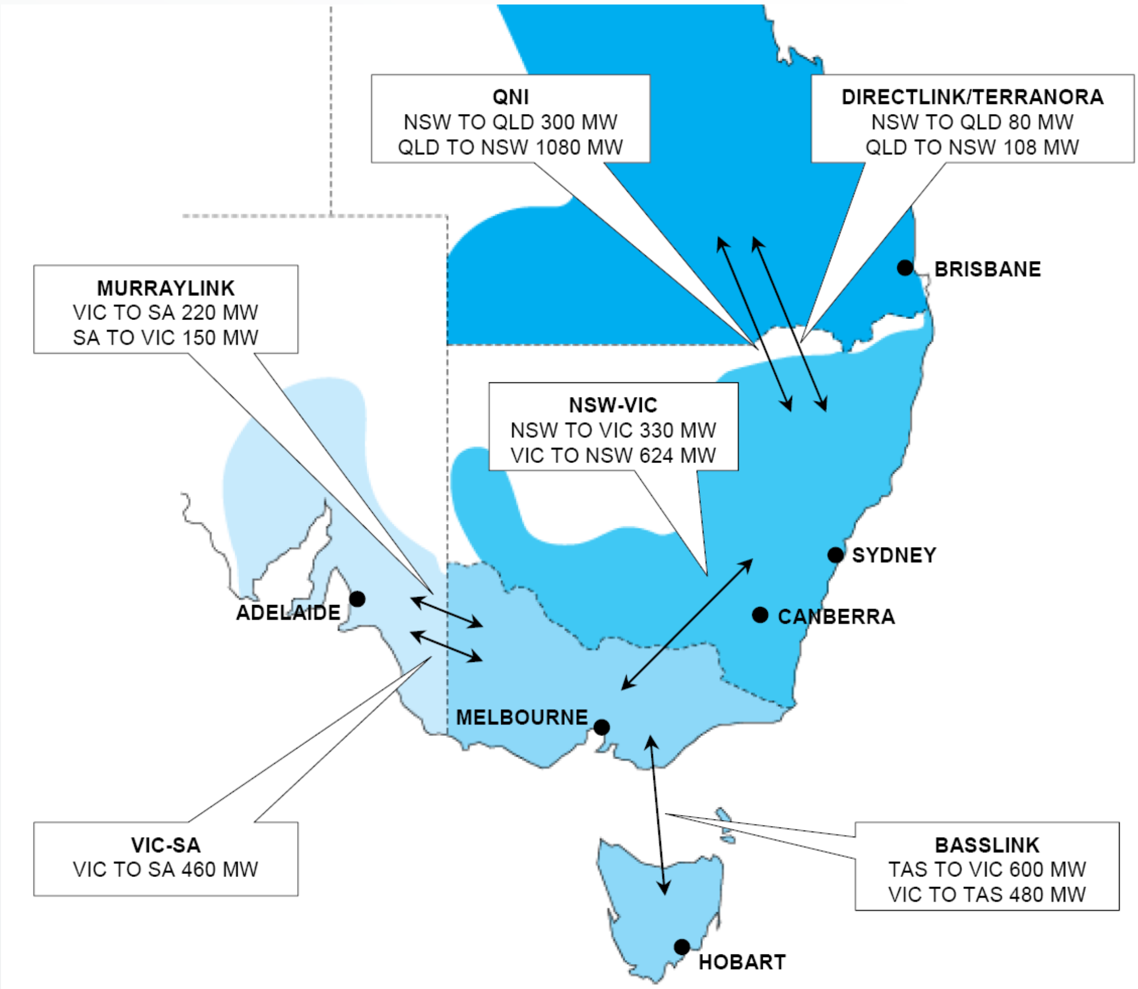
The exception to the NEM’s surplus capacity beyond 2022-2023 is Queensland that has a reserve deficit timing of 2020-21 for 159 MW. However, the lifetime of a plant built to meet this reserve timing would also fall within the period of economically viable storage.

Additionally, major manufacturing closures elsewhere in the NEM frees-up supply for export to Queensland. These major closures include:

- car manufacturing in SA, NSW and VIC
- Alcoa’s smelter and roll mills in VIC and NSW

But Queensland is currently a net exporter of electricity to NSW and the interconnector constraints in Figure 9 reflect this role. Whether there is sufficient free capacity to import electricity to cover the reserve deficit of 159 MW, is unknown. However, economically viable storage would make this constraint issue immaterial. Section 2.4 discusses transmission investment.

**Figure 9: Interconnectors on the NEM**




(Source: Tamblyn 2008, p. 7)

### 2.4.2 LNG export prices hampering gas generation's potential as a bridging technology

Gas could replace coal as a "bridging technology" to reduce GHG emissions over the next few decades because gas only produces about half of the GHG emissions of coal (IEA 2011, pp. 18-22). However, the feasibility of gas as a bridging technology comes under question for two reasons:

- the proposed removal of the carbon price; and
- liquefaction of natural gas for the export

The proposed removal of a carbon price exacerbates investment uncertainty for gas generation because coal generators become relatively more economical than gas generators without a carbon price.

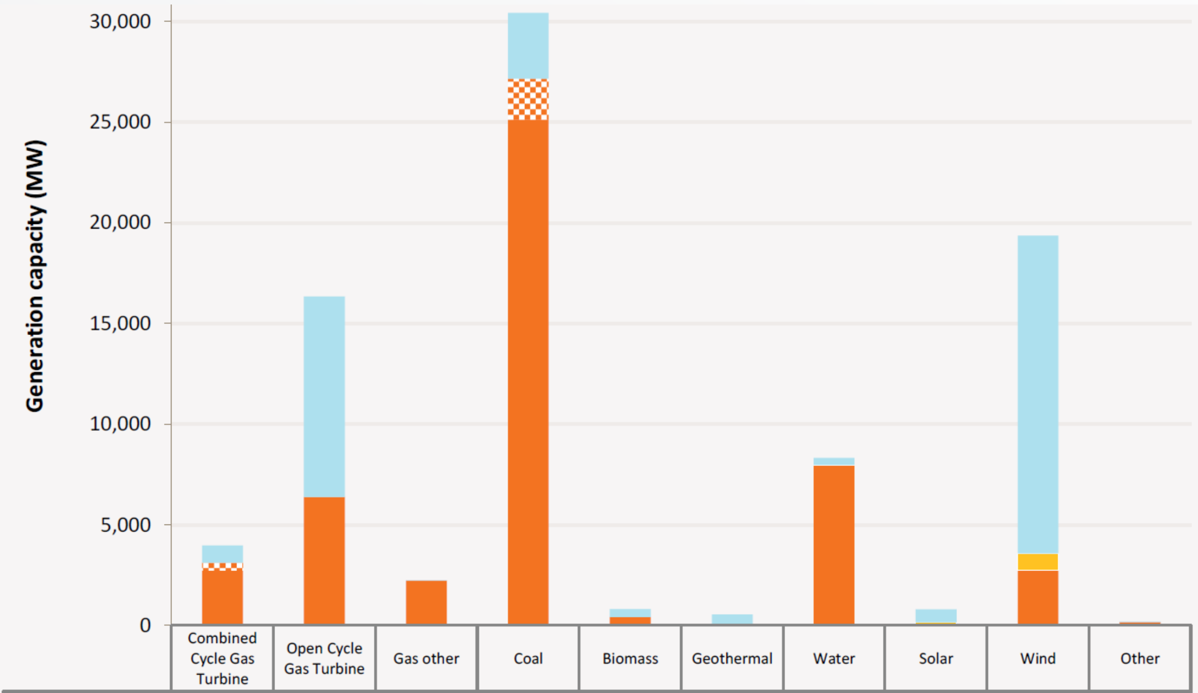
Section 2.4.2 discusses the liquefaction of natural gas for the export. This export of LNG creates an international linkage for gas prices in the NEM where gas prices are expected to rise from their traditional domestically determined price of $3-4/GJ to an internationally determined price of $11/GJ. Figure 10 shows the existing and proposed projects by generation. The proposed gas generation projects whose feasibility was based on historical gas prices will most probably prove infeasible with the newly international determined price for gas.

Figure 10 shows a pattern consistent with the sudden change in gas prices and uncertainty surrounding a carbon price affecting the feasibility of new gas power generation, namely:

- a large number of proposed OCGT projects but no committed projects for CCGT, OCGT and other gas; and
- withdrawal of existing generation.

The withdrawal is the 385MW Swanbank E Gas Power Station will cease operation for up to three years from 1 October 2014 and return to service before the projected timing of reserve deficits in Queensland (AEMO 2014c).

**Figure 10: NEM existing and proposed projects by generation type (MW)**




| | Combined Cycle Gas Turbine | Open Cycle Gas Turbine | Gas other | Coal | Biomass | Geothermal | Water | Solar | Wind | Other |
|---|---|---|---|---|---|---|---|---|---|---|
| Proposed | 860 | 9,955 | 15 | 3,270 | 387 | 550 | 337 | 639 | 15,799 | 10 |
| Committed | - | - | - | - | - | - | 1 | 146 | 834 | - |
| Existing (Withdrawn) | 385 | - | - | 2,015 | - | - | - | - | - | - |
| Existing | 2,726 | 6,384 | 2,226 | 25,144 | 419 | - | 7,987 | 2 | 2,742 | 172 |

(Source: AEMO 2014c)

But from a global climate change perspective it is immaterial whether gas is burnt in Australia or overseas because either case will provide “bridging technology”. In fact selling gas overseas may prove a better global climate change adaptation because Australia is better endowed with renewable energy resources than many Asian countries, which relatively reduces Australia’s need for gas as a bridging technology.

### *2.4.3 WTG: Low demand to wind speed correlation inducing price volatility*

Figure 10 shows both the largest proposed generation and committed generation is from WTG. This raises three issues:

- the proposed removal of the RET and carbon price inducing investment uncertainty;
- demand and WTG supply timing mismatch; and
- wholesale spot price volatility.

Simply absorbing the entire 15,799 MW of proposed and 834 MW of committed WTG needs careful consideration because there is a high correlation of demand between states and a high correlation of wind speed between states but little correlation between demand and wind speed between states, see Table 8.

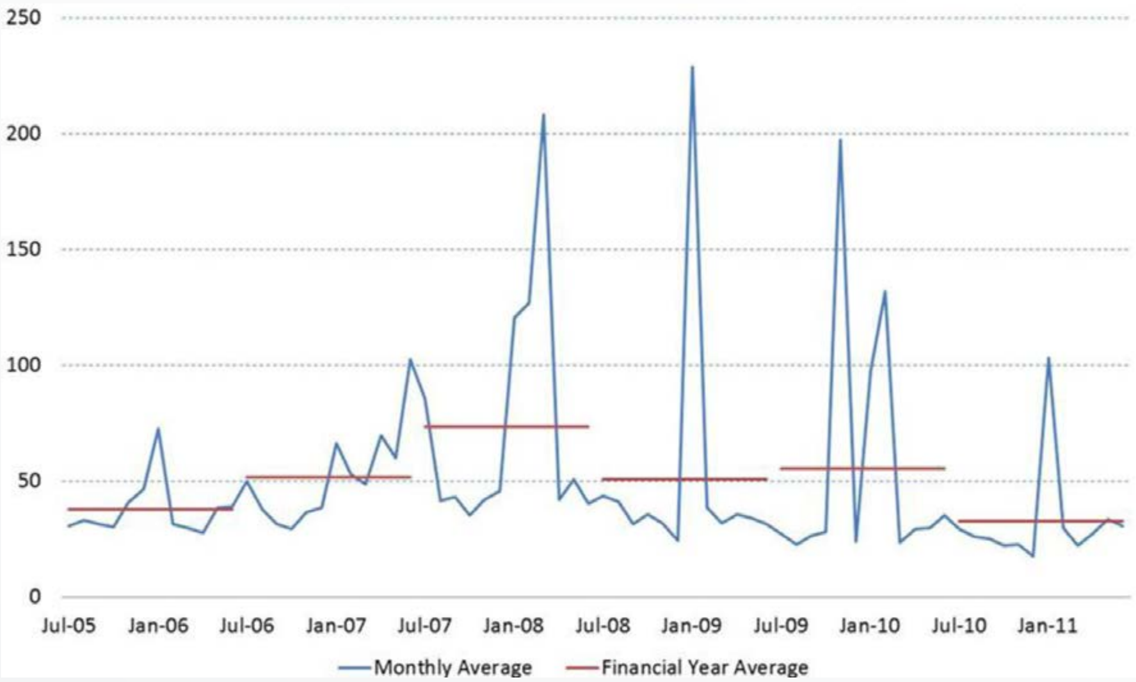
**Table 8: Correlation of wind speed and demand**

| | | Demand | | | | | Wind speed | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | NSW | QLD | SA | TAS | VIC | NSW | SA | TAS | VIC |
| Demand | NSW | 1 | | | | | | | | |
| | QLD | 0.83 | 1 | | | | | | | |
| | SA | 0.81 | 0.67 | 1 | | | | | | |
| | TAS | 0.72 | 0.54 | 0.58 | 1 | | | | | |
| | VIC | 0.89 | 0.75 | 0.85 | 0.78 | 1 | | | | |
| Wind Speed | NSW | 0.08 | 0.11 | 0.05 | 0.1 | 0.07 | 1 | | | |
| | SA | -0.16 | -0.08 | -0.07 | -0.15 | -0.16 | 0.34 | 1 | | |
| | TAS | -0.06 | 0.04 | -0.06 | -0.04 | -0.04 | 0.31 | 0.24 | 1 | |
| | VIC | -0.08 | -0.05 | -0.06 | 0 | -0.05 | 0.44 | 0.64 | 0.47 | 1 |

- (Source: Bannister & Wallace 2011, p. 15)

A consequence of this demand and WTG supply mismatch are volatile wholesale spot prices. Wholesale spot prices are sensitive to the addition of such a large penetration of WTG whose marginal cost is nearly zero. This adversely affects the profitability of existing plant and the investment decisions for new plant. For instance South Australia that has Australia's largest penetration of WTG, has experienced both increased volatility and reduced average wholesale spot prices. The AMEC chairman (Pierce 2011) confirms this reduction in the average spot price for electricity in SA, see Figure 11.

**Figure 11: Average wholesale spot price in South Australia per MWh**




(Source: Pierce 2011, p. 7)

However, the AMEC chairperson also discusses the increase in volatility in spot price in Table 9 where there have been increases in half-hours with negative spot prices and increases in half-hours with spot prices above $5,000 and $300 per MWh.

**Table 9: South Australia's wholesale spot prices**

| Year | Number of half-hour prices in South Australia | | | |
|---|---|---|---|---|
| | Above $5,000/MWh | Above $300/MWh | Below $0/MWh | Below -$300/MWh |
| **2006** | 1 | 62 | 1 | 0 |
| **2007** | 3 | 78 | 10 | 2 |
| **2008** | 52 | 78 | 51 | 3 |
| **2009** | 50 | 97 | 93 | 8 |
| **2010** | 24 | 58 | 139 | 18 |

(Source: Pierce 2011, p. 8)

The large baseload capacity in SA and limited ability to export surplus electricity to VIC combine to exacerbate the effect of the large penetration of WTG in SA on the wholesale spot price when windy conditions can occur during periods of low demand and baseload capacity is unable to adequately: ramp-up, ramp-down, shut-down or start-up to accommodate WTG. Wholesale spot price volatility solutions include either increasing:

- fast ramping, start-up and shut-down capacity such as peaking gas (OCGT) in SA; or
- the thermal capacity of the interconnectors from SA to VIC

The previous section discusses the current adverse investment climate for OCGT investment, making new investment unlikely.

AEMO and ElectraNet (AEMO & ElectraNet 2013 ) identified the need to increase the thermal capacity of the SA to VIC interconnector in July 2016. AEMO's and ElectraNets'

(AEMO & ElectraNet 2013 ) decision to invest in expanding the SA-VIC interconnector are net market benefit through significant reductions in generation dispatch costs over the longer term. This allows more generation from WTG and thermal in SA to be exported from SA to VIC when low demand and windy conditions arise in SA. This results in cheaper electricity for VIC, helps address the negative spot prices in SA, and makes use of faster ramping generation in VIC rather than SA's wind's correlation with VIC's demand.

Further to system stability and wholesale spot price volatility, Parkinson (2011) claims that there are successful large installations in a number of countries where variability has not posed a major problem. For instance Jones (2011, p. 91) discusses the East German company 50Hertz that has 37% of electricity supplied by WTG. But 50Hertz can sell and send surplus electricity to Poland, Czech Republic, Austria, Denmark or the former West Germany, which would reduce the likelihood of negative prices.

Nevertheless, the transmission grid in Europe is more of dense mesh structure. In contrast, the NEM's transmission grid is more a long string stretching nearly the entire east coast of Australia. The mesh structure is better suited to absorbing volatile generation. As discussed above, the solution to SA's high WTG penetration problems was improving the interconnectedness SA with VIC. This solution could be extended by making the NEM's transmission grid more mesh like or increasing thermal capacity of the interconnectors.

However, installing the entire proposed WTG in Figure 10 would take the NEM's penetration of WTG far above 37% for the company 50Hertz, assuming no increase from other forms of generation. The percentage of WTG within the European grid is much smaller than 37%. Absorbing all the proposed WTG within the NEM potentially poses unknown stability problems. There are at least three solutions:

- increase the diversity of renewable generation;
- increase distributed generation on net surplus demand nodes; and
- energy storage.

The proposed plant at Collinsville is part of this drive for diversity in renewable energy that will help system stability.

Placing distributed generation on nodes of the grid where there is net deficit generation or net demand surplus that is more demand than generation.

The arbitrage opportunities for energy storage are particularly good from WTG with both extreme negative and positive wholesale spot prices shown in Figure 11. Energy storage also provides a means to defer transmission network investment induced by large penetration of WTG. However, the separate ownership of generation and networks presents an obstacle to energy storage owners' ability to capture the full economic benefits of energy storage deployment. This separation of ownership will slightly delay energy storage deployment sometime after it becomes economically advantageous to the NEM (MGI 2013).

### 2.4.4 Energy storage deferring transmission infrastructure investment

Appendix A presents the NEM's transmission network that the ANEM model uses to address the research questions in this report. This section justifies the simplifying assumption that the transmission topology stays the same for the lifetime of the proposed plant.

We assume the topology of the transmission network in Appendix A stays the same the lifetime of the proposed plant for four reasons:

- Reserve capacity
- Energy storage
- Over-forecasting demand and gold-plating
- Real time measurement

The regional reserve deficit timings in Table 4 show the existing supply sufficient unit after 2022-23 at which time energy storage becomes economically viable to enable investment deferment in network infrastructure. Compounding this excess capacity, Section 2.2.8 discusses the over-forecasting of demand by NSP, which lead to building network infrastructure in excess of actual demand or gold-plating. Finally, there is the switch from normal to real-time rating of the thermal capacity of transmission lines that will allow better use of the existing infrastructure. See Transmission Network Service Providers (TNSP 2009, p. 4) for details.

However, we acknowledge that the installation of further WGT may require expanding the capacity of the transmission lines for the participants in the NEM to increase their net benefit from WGT until energy storage becomes economical viable.

### 2.4.5 Supply Summary

Uncertainty surrounding generation investment includes falling total demand, changing climate change policy and increasing fossil fuel prices. Additionally, there is the decreasing costs of renewable generation promoting a wait and see attitude.

Appendix B discusses the known closures and mothballing of generation plant and future deployment of WGT and transmission grid investments but beyond this time we assume that no further investment will occur to meet “Total demand” for the lifetime of the proposed plant. These assumptions are based on the permanent structural changes in total demand discussed in Section 2 and the advent of economically viable energy storage within the next 10 years allowing investment deferment in both transmission and generation.

## 2.5 Forecasting wholesale spot prices for the lifetime of the proposed plant using the ANEM model

The ANEM model determines the dispatch and wholesale spot prices from the interaction of the NEM's demand and supply discussed in Sections 2.2 and 2.4. Appendix B, in Section 9, discusses the AEMO model in detail and Appendix A, in Section 8, shows the network structure used by the AEMO model. The following description provides a simplified computer input-output overview of the ANEM model.

The inputs of the ANEM model are:

- half hourly electricity "total demand" for 52 nodes in the NEM;
- parameter and constraint values for 68 transmission lines and 315 generators;
- carbon price;
- fossil fuel prices; and
- network topology of nodes, transmission lines and generators.

The outputs of the ANEM model are:

- wholesale spot price at each node (half hourly),
- energy generate by each generator (half hourly),
- energy dispatched by each generator (half hourly),
- transmission flow in each transmission line (half hourly), and
- carbon dioxide emissions for each generator (daily).

Collinsville is situated on node number 3 called *'North'* in Figure 15 in Appendix A. Section 2.3 briefly describes the preparation of "total demand" using a typical meteorological year (TMY) selected from the years 2007-12. Section 3.2 discussed the data preparation in more detail.

### 2.5.1 The effect of the plant's proposed dispatch profile the on spot prices in the NEM

The ANEM model helps study the interaction of the proposed plant with the NEM. However, the 30 MW output of the plant is tiny relative to 6,400 MW, the average total demand in Queensland for the proposed operating time (AEMO 2014a), and so is unlikely to affect wholesale spot prices. Locational marginal prices (LMP) are the wholesale spot prices for the proposed plant's node. If LMPs are insensitive to the dispatch of the plant, the plant lacks market power. Consequently, the plant is a pure price taker, so its dispatch can be optimised independently of its interactions with the NEM. Section 7 proposes investigating the sensitivity of the wholesale spot prices to the dispatch of the proposed plant.

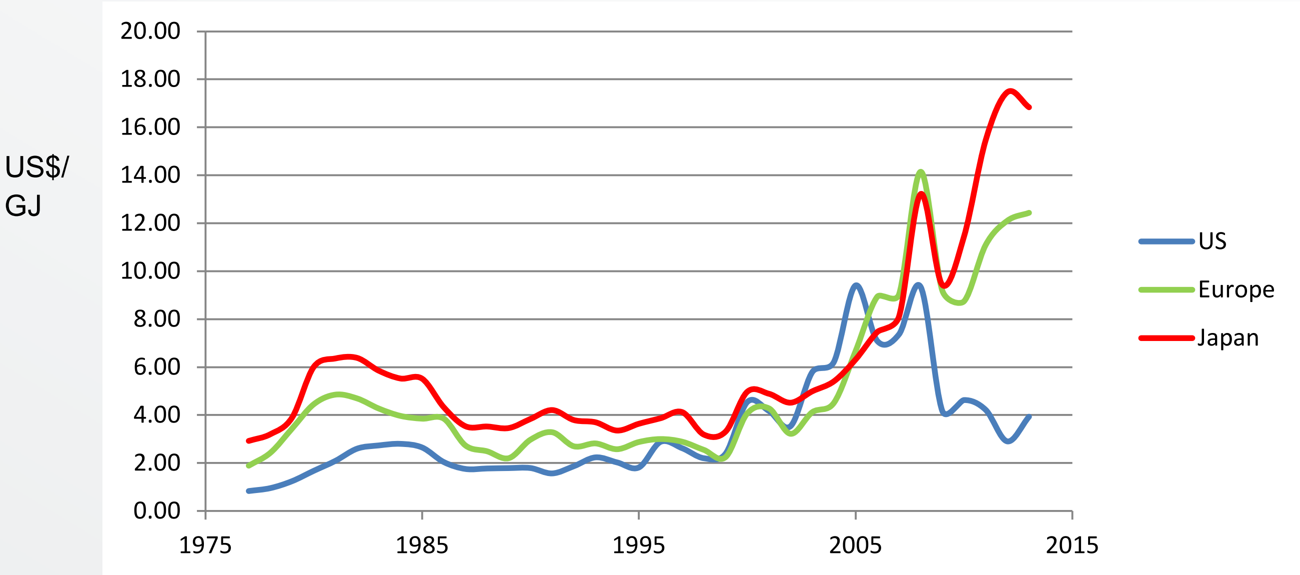
### 2.5.2 The effect of gas prices on wholesale spot prices

The profit of the plant's LFR component is largely subject to the weather and wholesale spot prices and since its marginal costs are nearly zero, dispatching its entire yield is profit maximising. In comparison, the gas component's supply is from a stranded asset whose supply is \$5/GJ, so independent of what happens with international gas prices. This gives the gas component an advantage compared with other gas generators whose gas prices would be subject to international prices and their ability to secure long-term gas supply contracts.

However, the profit of the proposed plant is indirectly subject to the market price of gas because the price of gas and coal largely determine the wholesale spot price of electricity. Nevertheless, an increase in gas prices relative to coal would produce a substitution from gas to coal generation, which would moderate increases in electricity prices. The sensitivity of the plant's profits to changes in gas prices requires investigation. Such a sensitivity study requires a range of possible future gas prices.

Currently, the pricing of gas on the east coast of Australia is going through a dramatic transformation because the once isolated domestic market is now linked to the rest of the world through liquefied natural gas (LNG) exports. The AEMC (2013) discusses how this linkage will determine the east coast's market price for gas and that price are unlikely to return back to the historic levels of \$3-4/GJ. Figure 12 compares Japan's LNG and US's and Europe natural gas prices in nominal US\$ per gigajoule.

**Figure 12: Comparing Japan's LNG and Europe's and US's natural gas prices**




(Source: World Bank 2014)

Figure 12 can provide some indication of the range of future gas prices in eastern Australia but factors affecting the price in the US, Europe and Japan require considering. In the US, there are restrictions on the export of gas and there is a surplus of gas in the domestic market. Therefore, the current low price of gas in the US is of little guidance in estimating the future cost of gas in Australia but if the US reduced the export restriction, the price of gas in Japan is likely to decline. The closure of nuclear plants in Japan and Germany after the Fukushima accident has caused price increase in both Japan and Europe but more sharply in Japan.

Figure 12 shows the price of LNG in Japan. The Wood, Carter and Mullerworth (2013) estimates the cost to convert natural gas to LNG and transport from Australia to Asia is about \$5 to \$6 per gigajoule. Therefore, the "export parity" price would be about \$11/GJ. This parity price contrasts sharply with the recent domestic prices of \$3-4/GJ.

BREE (2013) discusses seven contracts for gas settling between \$7-8/GJ and one contract, the latest, settling between \$8-9/GJ. In a high growth scenario, BREE (2013) estimates a gas price above $10/GJ by 2023. BREE (2013) uses LNG netback pricing in export parity calculations that is *the LNG Free On Board (FOB) export price less the costs of liquefaction and transportation.*

There is the possibility that countries may take substantial action over climate change during the lifetime of the plant. This would engender a larger switch from coal to gas because gas generation can act as a bridging technology. Additionally, China may simply want to address its air pollution problem. This would also engender a switch from coal to gas. Both cases would put upward pressure on LNG prices. There is also the current spike in LNG prices induced by Japan's and Germany's closure of their nuclear plants. However, putting downward pressure on prices are the new processes that enable access to new deposits of gas, whose supply has yet to develop fully and the US's surplus supply of gas that is being readied for export.

The following research questions address the sensitive of the plant to gas prices.

- How sensitive are wholesale spot prices to gas price change from $8.50/GJ to $11/GJ?
- How sensitive is the plant's revenue to gas price change from $8.50/GJ to $11/GJ?

Section 3 discusses how the ANEM model is used to address this research question.

## 2.6 Conclusion

The literature review has both established the research questions and provided direction for the methodology to address these questions.

### 2.6.1 Research questions

The report has the following overarching research questions:

> *What is the expected dispatch of the proposed plant's gas component given the plant's dispatch profile and expected LFR yield?*
>
> *What are the wholesale spots prices on the NEM given the plant's dispatch profile?*

The literature review has refined the latter research question into four more specific research questions ready for the methodology:

- *What are the wholesale spots prices on the NEM for a gas price of $8.50/GJ given the plant's dispatch profile?*
- *How sensitive are wholesale spot prices to a gas price change from $8.50/GJ to $11/GJ given the plant's dispatch profile?*
- *What is the plant's revenue for a gas price of $8.50/GJ given the plant's dispatch profile?*
- *How sensitive is the plant's revenue to gas price change from $8.50/GJ to $11/GJ given the plant's dispatch profile?*

# 3 Methodology

This chapter describes the methods used to address the operationalised research questions arising from the literature review in the previous chapter. Section 2.5.2 discusses the estimation of the expected lower and upper bounds for domestic gas prices to determine the sensitivity of the NEM's wholesale spot prices and plant's revenue to gas prices. Five operationalised research questions form the main section headings in this methodology chapter:

- *What is the expected TMY dispatch of the proposed plant given the plant's dispatch profile for hours of the week and expected TMY yield of the LFR?*
- *What are the wholesale spots prices on the NEM for a gas price of $8.50/GJ given the plant's TMY dispatch profile?*
- *How sensitive are wholesale spot prices to a gas price change from $8.50/GJ to $11/GJ given the plant's TMY dispatch profile?*
- *What is the plant's revenue for a gas price of $8.50/GJ given the plant's TMY dispatch profile?*
- *How sensitive is the plant's revenue to gas price change from $8.50/GJ to $11/GJ given the plant's TMY dispatch profile?*

## 3.1 What is the expected TMY dispatch of the proposed plant given the plant's dispatch profile for hours of the week and expected TMY yield of the LFR?

The expected TMY dispatch of the proposed plant is calculated from the plant's total dispatch by hour of week shown in Table 3 and the expected yield from the LFR for a TMY derived in the yield report. The preface discussed the yield report.

The expected TMY dispatch of the proposed plant's gas components is also calculated from the difference between the expected TMY dispatch of the proposed plant and the TMY yield from the LFR.

The expected TMY dispatch of the proposed plant is used in:

- Research questions 2 and 3 to load-shave the plant's dispatch profile from the demand profile of the NEM's "North" node in Figure 15; and
- Research questions 4 and 5 to calculate total plant revenue.

## 3.2 What are the wholesale spots prices for the lifetime of the plant given a gas price of $8.50/GJ, the plant's TMY dispatch profile and the NEM's associated TMY demand profile?

The ANEM model forecasts wholesale spot prices for the lifetime of the proposed plant from electricity demand and electricity supply forecasts. The market definitions of demand and supply differs between the ANEM model and AEMO (2012a, sec. 3.1.2) in one respect. The ANEM model includes large non-scheduled WTG when calculating the "market" wholesale spot price whereas the AEMO's total [market] demand excludes large non-scheduled WTG. This distinction between large and small non-scheduled WTG has implications for the total demand normalisation process in Subsection 1. Section 2.2.2 discusses AEMO's "total demand" in more detail.

Subsections 1 and 2 respectively discuss methodologies for these demand and supply forecasts. Appendix B discusses the ANEM methodology in detail and Appendix A presents the ANEM's topology of the transmission lines, nodes, generators and load serving entities.

### 3.2.1 Forecasting total demand in the NEM for the lifetime of the proposed plant

This section discusses the methodology to produce the TMY total demand profile for the NEM from the years 2007-2012. This methodology uses the gross demand concept and Equation 1 from the literature review in a six-step process to develop a TMY normalised total demand profile.

- Grossing-up total demand with small non-scheduled solar PV
- Grossing-up total demand with small non-scheduled WGT
- Grossing-up total demand with large non-scheduled WGT
- Netting-out gross demand with December 2012 non-scheduled generation capacity to form normalised total demand
- Load shaving the proposed plant's dispatch from the normalised total demand
- Developing a TMY normalised total demand profile using the proposed plant's TMMs

These six-steps form the headings in this demand forecasting section.

The first three steps involved grossing up the total demand for the 50 demand nodes in the NEM using half-hourly data from 2007 to 2012. Equation 2 describes the relationship amongst total and gross demand and non-scheduled generation used in this report. The non-scheduled WGT are separated into Small Generation Units (SGU) and Large Generation Units (LGU) because the SGU and LGU data comes from different sources and the power output is calculated differently. The Clean Energy Regulator (CER 2012) provides the aggregated SGU name plate values by postcode for both non-scheduled solar PV and wind but excludes LGU. The BoM (2012) measures wind speed 30 m above ground level, which is suitable for wind SGU but unsuitable for LGU that range between 60 to 140 m above ground level.

**Equation 2: Grossing-up total demand 2007-12**

$$d_g(t, n) = d_t(t, n) + (p_{ss}(t, n) + p_{ws}(t, n))/1000 + p_{wl}(t, n)$$

Where:

| | | |
|---|---|---|
| $d_g$ | = gross demand (MW) | |
| $t$ | = time (half hourly) | |
| $n$ | = node | |
| $d_t$ | = total demand (MW) | |
| $p_{ss}$ | = non-scheduled solar PV SGU (kW) | (Sec. 3.2.1.1) |
| $p_{ws}$ | = non-scheduled wind SGU (kW) | (Sec. 3.2.1.2) |
| $p_{wl}$ | = non-scheduled wind LGU (MW) | (Sec. 3.2.1.3) |

The CER (2012) database understates the amount of SGU installations because the database actually records renewable energy certificate that have been successfully redeemed, so does not include certificates that are pending registration or have been failed by the CER or its predecessor.

The CER database provides an aggregate figure of the redeemed certificate for the years 2001 to 2009 and provides monthly data from January 2010 onwards. This entailed some interpolations to convert the SGU kW installation data into half-hourly form suitable for this report. The assumption is made that prior to 2006 that there was zero SGU installed. This is not too onerous an assumption as the amount of SGU installed over 2010 and 2012 dwarfs the installations prior to January 2010.

For wind and solar PV SGU the post codes of the CER (2012) data are first converted to SA2 (ABS 2012). The perimeters of SA2 are described by a hierarchical sets of latitudes and longitudes describing smaller areas within Esri shape files (ABS 2011). These perimeter latitudes and longitudes are averaged to produce a latitude and longitude to approximate the centre of the SA2. This centre allows matching with the closest weather stations for power calculations and to find the closest node to attribute the power generated. Approximating an area with a point is justifiable because the SA2s are small areas. SA2 have an average population of about 10,000, with a minimum population of 3,000 and a maximum of 25,000. There are about 2,200 SA2s in Australia.

The CER (2012) database provides the name plate value of the SGU installed but lacks details of the SGU's manufacturer or model. So, simplifying assumptions are made to model generic wind and solar PV generators.

#### *3.2.1.1 Grossing-up total demand with small non-scheduled solar PV*

This section describes how the half hour solar intensity and temperature readings from BoM (2012) and the nameplate value of the solar PV from CER (2012) are converted into power (kW) generated per node.

AEMO (2012b, p. 65) notes that a typical solar PV array consists of multiple panels which produce direct current (DC) power. Panel generation output is roughly linear with the incident solar insolation, but is also impacted by the cell temperature. This simple relationship is captured in Equation 3, which calculates the usable alternating current (AC) power generated by solar PV for this report and is adapted from the US National Renewable Energy Laboratory (NREL) (Marion et al. 2001). Other factors influence generation, such as, the effect of wind speed on PV module temperature and changes in inverter efficiency with power but Marion et al. (2001) consider these factors are small relative to measurement error, so ignore them in their calculations.

**Equation 3: Grossing up total demand with non-scheduled solar PV 2007-12**

$$p_s(t, x) = d * i(t, x) * n(t, x) * (1 - 0.005 * (T(t, x) - 25))$$

Where:

$p_s$ = usable AC power generated by solar PV (kW)
d = de-rating factor for converting total DC generated into usable AC
t = time (half hourly intervals)
x = location (SA2 using latitude and longitude)
i = solar intensity (kW/m$^2$)
n = name plate values at STC (kW generated per kW/m$^2$ solar intensity)
T = ambient temperature ($^o$C)

The de-rating factor d for converting total DC generated into usable AC incorporates losses by inverters and resistance in wiring. The US (NREL 2013) estimates that the de-rating value for the whole of the NEM is 0.77. This simplifying assumption is justified because neither the models nor manufacturers of the panel are unknown.

Regarding solar intensity *i*, the BoM (2013) provides hourly satellite derived DNI and GHI estimates in kW/m$^2$ for a five km grid across the NEM region. This report uses the simplifying assumption that the useable solar intensity is the average of the DNI and GHI because the installation angle of the solar PV panels is unknown. The gridded data closest to the SA2 containing the solar PV is used. The hourly satellite data is interpolated to form half hourly solar intensity data.

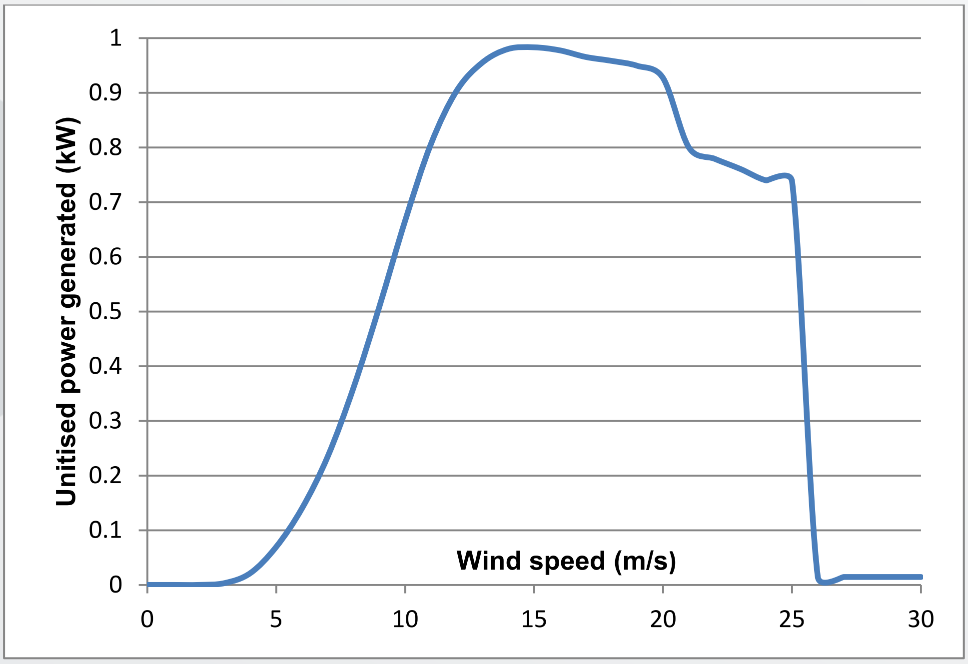
A nameplate capacity *n* of a panel is typically expressed in terms of its output under standard test conditions (STC) to provide a reference point for plant design. The STC are 1000 W/m$^2$ insolation with a cell temperature of 25°C. The *n* in Equation 3 represents the total name plate value present every half hour in each SA2.

Regarding ambient temperature *T* in Equation 3, an increase in temperature above 25 °C reduces the power produced by solar PV and a decrease below 25°C increases the power. The average temperature of four weather stations closest to the centre of the ABS statistical area containing the solar PV is used to provide both a more representative temperature of the region and covers any missing data. Temperature has a linear relationship in Equation 3, which allows the use of the average temperature across the weather stations.

#### *3.2.1.2 Grossing-up total demand with small non-scheduled WGT*

A power curve relates the wind speed (m/s) to the power (kW) produced by a wind turbine generator. Figure 13 shows the power curve used in this project, which is developed from averaging the power curves of 69 different wind generators sourced from the Idaho National Laboratory (INL 2005).

**Figure 13: Unitised power curve for generic wind generator**




(Source: Bell, Wild and Foster 2013)

Before averaging, the individual power curves are normalised to a value of 1 kW, so the project's power curve represents a generic 1 kW wind generator response to wind speed.

Equation 4 shows how the nameplate value n and power curve function f is used to convert the wind speed into power generated for each SA2 containing small wind generators for each half hour.

**Equation 4: Grossing-up total demand with non-scheduled wind 2007-12**

$$p_{wn}( t, x ) = n( t, x ) * f( s( t, x ) )$$

Where:

$p_{wn}$ = power generated by non-scheduled wind (kW generated)
t = time (half hourly intervals)
x = location (SA2 by latitude and longitude)
n = nameplate value (kW installed) *(Source: CER 2012)*
f = power curve (kW generated per kW installed) *(Source: INL 2005)*
s = wind speed (m/s) *(Source: BoM 2012)*

However, the half-hourly data from the weather stations is incomplete, so the four closest weather stations to the centre of the SA2 are used in the calculation where the power per weather station is calculated, which is then averaged. Finally the power by SA2 is converted into power by node.

#### *3.2.1.3 Grossing-up total demand with large non-scheduled WGT*

The power from large non-scheduled WGT is calculated using AEMO (2014e) five-minute non-scheduled generation output data by wind farm for the years 2007-12. The five-minute data is averaged across six intervals to produce half-hourly output by wind farm. This half-hourly data is aggregated across the non-scheduled generators located on the same node to produce half-hourly data by node. Table 10 shows the large non-scheduled wind farms included in this report. Appendix A provides diagrams of the node locations.

**Table 10: Large non-scheduled wind farms included in modelling**

| *Wind Farm* | *Node Location* | *Capacity MW* |
|---|---|---|
| Capital | Canberra | 140.7 |
| Cullerin Range | Canberra | 30.0 |
| Yambuk | South West, VIC | 30.0 |
| Portland | South West, VIC | 102.0 |
| Waubra | Regional, VIC | 192.0 |
| Challium Hills | Regional, VIC | 52.5 |
| Canundra | South East, SA | 46.0 |
| Lake Bonney 1 | South East, SA | 80.5 |
| Starfish Hill | Adelaide | 34.5 |
| Wattle Point | Mid-North, SA | 90.8 |
| Mount Millar | Eyre Peninsula | 70.0 |
| Cathedral Rock | Eyre Peninsula | 66.0 |
| Woolnorth | Burnie, TAS | 139.8 |
| | *Total* | *1,267.9* |

(Source: AEMO 2014e)

Table 11 shows the large WGT non-scheduled wind farms excluded from modelling in this report because AEMO lacks data on these wind farms as they lack a *Supervisory Control and Data Acquisition* (SCADA) connection with the AEMO system. However, the contribution from these wind farms is 3.2 per cent of total wind capacity, so ameliorating any concerns about their omission.

**Table 11: Large non-scheduled wind farms excluded from modelling**

| *Wind Farm* | *Node Location* | *Capacity MW* |
|---|---|---|
| Windy Hill | Far North, QLD | 12.0 |
| Crookwell | Marulan, NSW | 4.8 |
| Blayney | Mt Piper, NSW | 9.9 |
| Toora | Morwell, VIC | 21.0 |
| Wonthaggi | Morwell, VIC | 12.0 |
| Codrington | South West, VIC | 18.2 |
| Hepburn | Regional, VIC | 4.1 |
| | *Total* | *82.0* |
| | *% of total wind capacity* | *3.2%* |

Table 12 shows the semi-scheduled wind farms included in this report but semi-scheduled wind is excluded from the grossing-up process in this section because semi-scheduled wind farms are included in AEMO's definition of total [market] demand discussed in Section 2.3.1 and shown in Equation 1. However, this section includes Table 12 to enable comparison with the non-scheduled wind farms in Table 10 and Table 11. The large wind generation modelling in this report comprises thirteen non-scheduled and thirteen semi-scheduled wind farms with a combined capacity of 2,471.8 MW, which represents 96.8 per cent of total installed capacity of operational wind farms in the NEM at the end of 2012. This semi-scheduled wind is discussed in Section 3.2.2.

**Table 12: Large semi-scheduled wind farms included in modelling**

| *Wind Farm* | *Nodal Location* | *Capacity MW* |
|---|---|---|
| Gunnings Range | Canberra | 46.5 |
| Woodlawn | Canberra | 48.3 |
| Oaklands Hill | South West, VIC | 67.2 |
| Macarthur | South West, VIC | 420.0 |
| Lake Bonney 2 | South East, SA | 159.0 |
| Lake Bonney 3 | South East, SA | 39.0 |
| Snowtown 1 | Mid-North, SA | 98.7 |
| Hallett 1 | Mid-North, SA | 94.5 |
| Hallett 2 | Mid-North, SA | 71.4 |
| Clements Gap | Mid-North, SA | 56.7 |
| Waterloo | Mid-North, SA | 111.0 |
| North Brown Hill | Mid-North, SA | 132.3 |
| The Bluff | Mid-North, SA | 52.5 |
| | *Total* | *1,203.9* |
| | *Combined Total* | *2,471.8* |

(Source: AEMO 2014d)

#### *3.2.1.4 Netting out gross demand with December 2012 non-scheduled generation capacity to form normalised total demand*

The gross demand for the years 2007-12 from the above three steps is used in this step. The normalised total demand is the gross demand less the theoretical power output from the small non-schedule WTG and non-scheduled solar PV given the nameplate values for December 2012 and the weather present during the years 2007-12.

The large non-scheduled WTG is optimised within the ANEM model, so ignored in this normalisation process.

#### *3.2.1.5 Load shaving the proposed plant's dispatch from the normalised total demand*

This step load shaves the proposed plant's dispatch from the normalised total demand derived in the above step. The dispatch from the proposed plant is calculates in research question 1.

#### *3.2.1.6 Developing TMY normalised total demand profile using proposed plant's TMY*

The TMY normalised total demand profile involves selecting the 12 typical meteorological months (TMMs) from the years 2007-12 of the normalised total demand. The 12 TMMs are selected in the yield report to represent the typical yield from the proposed plant's LFR rather than the typical demand. This method provides consistency between the reports and maintains focus on the dispatch of the proposed plant.

### *3.2.2 Forecasting supply for the lifetime of the proposed plant*

This report uses latest *Electricity Statement of Opportunities* (ESO) (AEMO 2013a) to provide a forecast of supply. After the time horizon of the ESO, energy storage is assumed to play a significant role in determining AEMO's "total demand" both by deferring investment in generation and transmission. Additionally, energy storage plays a significant role in allowing growth in "gross demand" without growth in "total demand" that is electricity produced and consumed within the NEM region but outside the market. Section 2 discusses in more detail.

As discussed above, both semi-scheduled and large non-scheduled wind generation operational over the period 2007 to 2012 are incorporated in the ANEM model as generators. However, in the ANEM model the output of the wind farms are aggregated by node calculated by summing the output of all non-scheduled and semi-scheduled wind farms located within a particular node. Thus, we are not modelling the individual wind farms themselves but are aggregating their output within a node to derive an aggregated nodal based wind generation source. Moreover, we are restricting attention to those nodes that contain operating wind farms. We have not included assessment of the impact of proposed wind farms located at nodes that do not contain operational wind farms such as Armidale, Marulan, Wellington and Yass nodes in NSW.

The default setting adopted for modelling purposes is for wind generation not to be dispatched by bidding in WTG output at the 'Value-of-Lost-Load' (VOLL), which is assumed to be $10000/MWh. This default setting is overridden when the output of the nodal based wind generation source exceeds 10MW. This output value was determined by summing the half-hourly output traces associated with both non-scheduled and semi-scheduled wind farms located in each node with this data sourced from half-hourly averages of five-minute data contained in AEMO (2014d, 2014e).

When the default setting is overridden, the nodal based wind ‘entities’ are dispatched according to short run marginal cost coefficients calculated from averages of equivalent cost coefficients of all wind farms located in the node. These coefficient values lie in the range of $3.39/MWh to $4.69/MWh, thus representing some of the cheapest sources of generation when dispatched.

## 3.3 How sensitive are wholesale spot prices to a gas price change from $8.50/GJ to $11/GJ given the plant’s dispatch profile?

This research question compares wholesale spot prices for the proposed plant given gas prices of $8.50/GJ and $11/GJ. Research question 2, in the previous section, calculates the wholesale spot prices for a gas price of $8.50/GJ. Research question 2’s methodology is used to calculate the wholesale spot prices for a gas price of $11/GJ.

## 3.4 What is the plant’s revenue for a gas price of $8.50/GJ given the plant’s dispatch profile?

This research question calculates the plant’s revenue using the dispatch calculated in research question 1 and the whole sale spot prices in research question 2.

## 3.5 How sensitive is the plant’s revenue to gas price change from $8.50/GJ to $11/GJ given the plant’s dispatch profile?

This research question uses the dispatch and wholesale spot prices from the previous research questions.

## 3.6 Conclusion

This section, building on the literature review, presents the methodologies ready to apply to the operationalised research questions to provide the results in the next section.

# 4 Results and analysis

[This section is deliberatively left blank.]

# 5 Discussion

The discussion in this preliminary or draft report addresses the research questions but a more comprehensive discussion will be provided in the final report when all the results are available. Five operationalised research questions form the main section headings in this discussion chapter:

## 5.1 What is the expected TMY dispatch of the proposed plant given the plant's dispatch profile for hours of the week and expected TMY yield of the LFR?

Table 3 shows the dispatch profile of the proposed plant by time of week but this profile may be revised once the yield from the LFR component of the plant is known. If the LFR yield is frequently above 30MW, paying for a higher capacity transmission line to the NEM could be warranted. This would entail altering the profile in Table 3.

Physically, a small excess above 30 MW could easily be accommodated within the existing transmission level but legally, the 30 MW maximum may be required to maintain non-scheduled status. However, there are some non-scheduled wind farms significantly above 30 MW.

## 5.2 What are the wholesale spots prices for the lifetime of the plant given a gas price of $8.50/GJ, the plant's TMY dispatch profile and the NEM's associated TMY demand profile?

Section 2.4.2 discusses the latest gas price contract written for between $8-9/GJ, so $8.50/GJ becomes the expected lower bound of gas prices.

## 5.3 How sensitive are wholesale spot prices to a gas price change from $8.50/GJ to $11/GJ given the plant's dispatch profile?

Section 2.4.2 also discusses the recent spike in Japanese LNG gas prices. The non-liquefaction export-parity prices of $11/GJ forms the expected upper bound prices for gas.

## 5.4 What is the plant's revenue for a gas price of $8.50/GJ given the plant's dispatch profile?

This research question provides the expect revenue from the plant given the lower bound gas price.

## 5.5 How sensitive is the plant's revenue to gas price change from $8.50/GJ to $11/GJ given the plant's dispatch profile?

This research question provides the revenue difference between the lower and upper bound gas prices.

# 6 Conclusion

This preliminary or draft report presents the complete literature review, arising research questions and methodology to address the research questions. The discussion in Section 5 analyses the research questions. The final form of the proposed plant's dispatch profile in Table 3 is contingent on the LFR yield results the yield report.

The methodology is in place to address the research questions to provide a more comprehensive discussion in the final report when all results are available. The processes for forecasting total demand, generation and wholesale spot prices for the NEM have been selected, so the project can proceed.

# 7 Further research

This section compiles the further research discussed elsewhere in this report.

## 7.1 Extending the reports TMY based years 2007-12 to include earlier year to remove La Nina bias

Section 2.3.6 discusses how the years 2007-12 used to form the TMY in this report have La Nina bias. So, the current TMY selection will under report the revenue for the proposed plant. In contrast, the years immediately prior to 2007 have El Nino bias. Incorporating earlier years would reduce the current La Nina bias. However, this would require developing disaggregated demand profiles suitable for use by the ANEM model that requires a demand profile for each of the 50 nodes on the NEM shown in Appendix A.

## 7.2 Wholesale spot price sensitivity to the proposed plant

Section 2.5.1 discusses the sensitivity of the wholesale spot prices to the introduction of the proposed plant. However, this sensitivity is expected to be extremely slight, negligible or trivial.

## 7.3 Other large non-scheduled generation on the NEM 2007-12

Table 13 shows large non-scheduled generators other than WTG but unlike WTG these generators are excluded from the report's modelling because given their small proportion of the NEM's total supply, the modelling overhead would be excessive to include within the ANEM model or normalise the generation as discussed in 3.2.1. AEMO (2014e) provides five-minute generation output data by generator for the years 2007-12.

**Table 13: Other large non-scheduled generation**

| *Name* | *Node Location* | *Generation Type* |
|---|---|---|
| Butlers Gorge | Tarraleah TAS | Hydro |
| Clover | Dederang VIC | Hydro |
| Cluny | Liapootah TAS | Hydro |
| Broken Hill GT 1 | Tumut NSW | Diesel |
| Broken Hill GT 2 | Tumut NSW | Diesel |
| Invicta Mill | Ross QLD | Sugar Cane (Bagasse) |
| Paloona | Sheffield TAS | Hydro |
| Pioneer Mill | Ross QLD | Sugar Cane (Bagasse) |
| Repulse | Liapootah TAS | Hydro |
| Rowallan | Sheffield TAS | Hydro |
| Rubicon | Melbourne | Hydro |
| Warragamba | Sydney | Hydro |
| Rocky Point | Moreton South QLD | Biomass (Bagasse/Wood Chips) |
| Callide A | Central West QLD | Coal |
| Angaston 1 | Mid-North SA | Diesel |
| Angaston 2 | Mid-North SA | Diesel |

(Source: AEMO 2014e)

## 7.4 Solar water heaters replacing electric waters heaters

Section 2.2.1 discusses technological innovation transforming the AEMO's "total" demand curve. One such innovation is the replacement of electric water heaters (EWH) with solar water heaters (SWH) where SWH shave demand from the early hours of the morning or other off-peak periods when EWH traditionally operated. Section 3.2.1 discusses the normalisation process to find the “total” demand in 2007-12, as if, the whole December 2012 installation of solar PV and small WTG were in place for the 2007-12. The process in 3.2.1 uses the CER (2012) database monthly MW installation of solar PV and small WTG by postcode. The database also includes monthly SWH installation by postcode. This normalisation process helps explain the decrease in the AEMO’s “total” demand and helps improve modelling of demand.

## 7.5 Poor correlation between wind speed and demand requiring more transmission

Table 8 shows the lack of correlation between wind speed and demand. However, WTG through the merit order effect does put down ward pressure on wholesale market prices. This market benefit is hampered by transmission bottlenecks, which are likely to be exacerbated with further deployment of WTG. This requires research into the dynamics between the transmission structure, wind speed and demand to optimise market benefit.

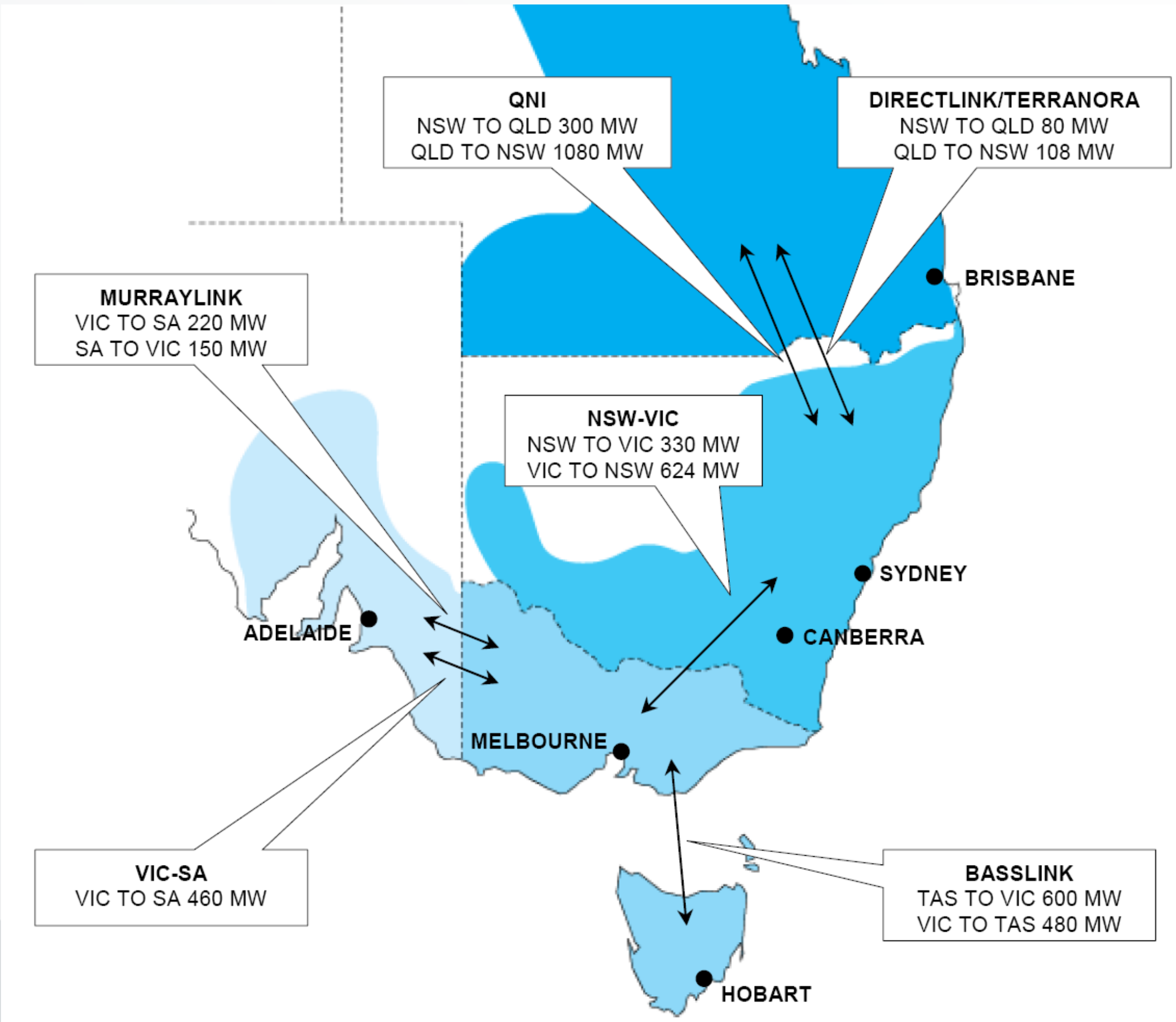
## 7.6 Poor correlation between wind speed and demand requiring more transmission

Table 9 shows the effect of WTG on South Australia’s wholesale spot process. This trend needs revaluating with more up to date data to capture the adaptive changes in transmission and generation.

# 8 Appendix A – Australian National Electricity Market Network

This appendix provides network diagrams of the nodes discussed in this report. These nodes are also known as load serving entities or demand regions. However, three of the nodes are supply only nodes without associated demand. Figure 14 shows the interconnectors between the states, which provides an overview of the more detailed state network diagrams in the following figures.

**Figure 14: Interconnectors on the NEM**




(Source: Tamblyn 2008, p. 7)

Regarding the numbering on the nodes, if the node number and demand region number are the same, just one number is placed on the node. If the node number and demand region number differ, both numbers are placed on the node in the following way: (node number, demand region number). For instance, (10, 11) is on the node at North Morton.

The proposed plant is attached to node number 3 called 'North'.

**Figure 15: Stylised topology of QLD transmission lines and Load Serving Entities**

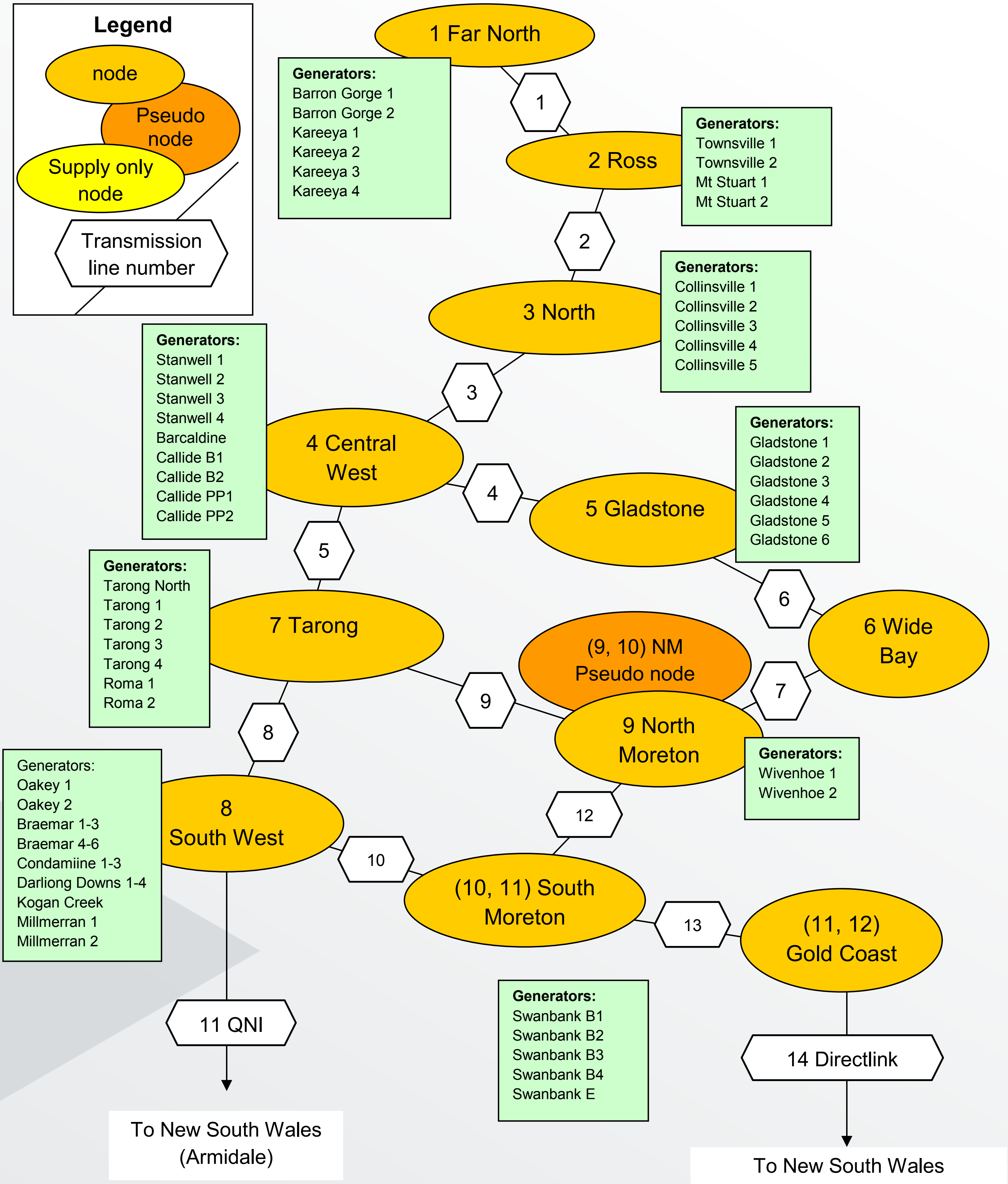


**Figure 16: Stylised topology of NSW transmission lines and LSE**

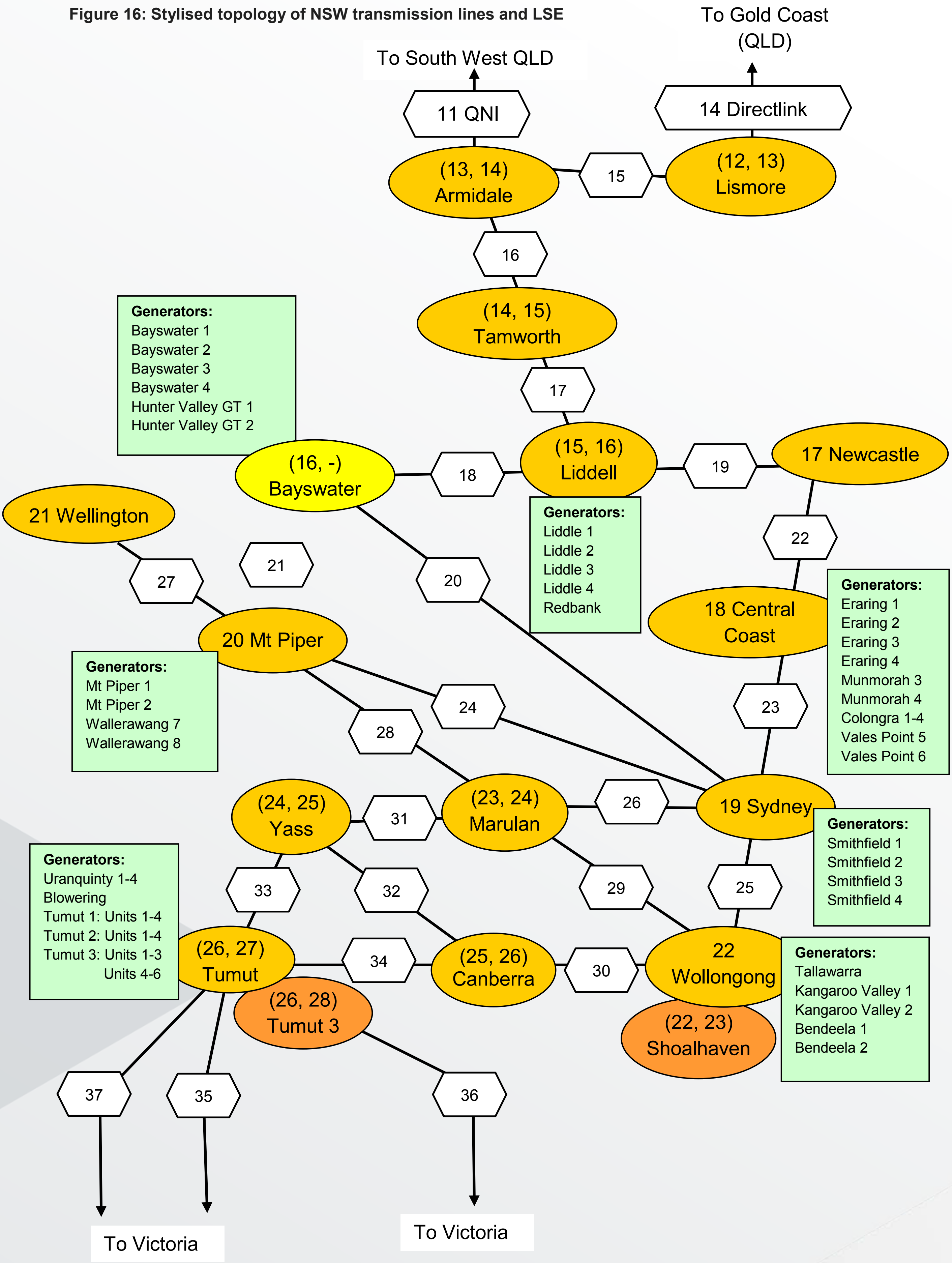


**Figure 17: Stylised topology of VIC transmission lines and Load Serving Entities**

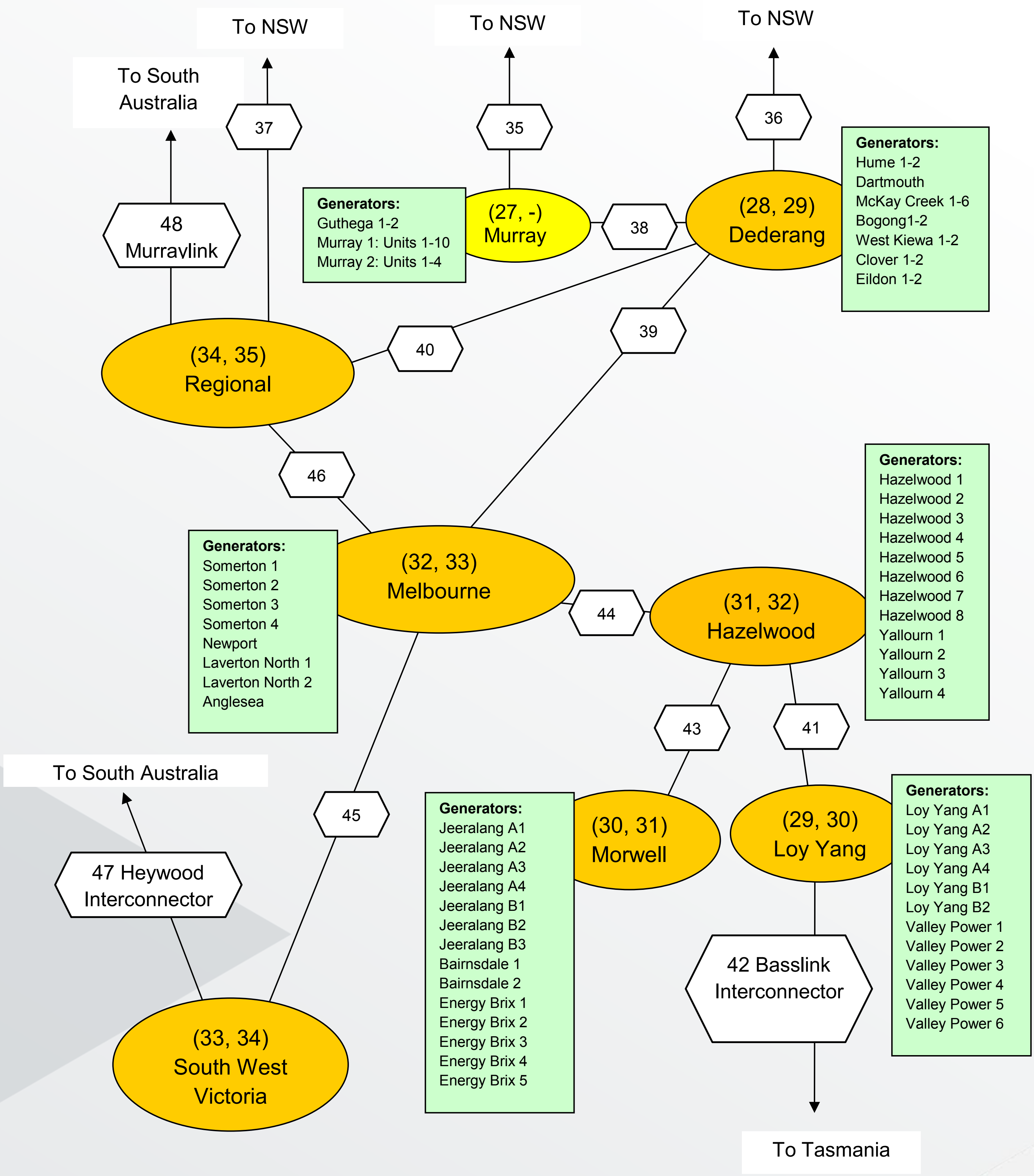


**Figure 18: Stylised topology of SA transmission lines and Load Serving Entities**

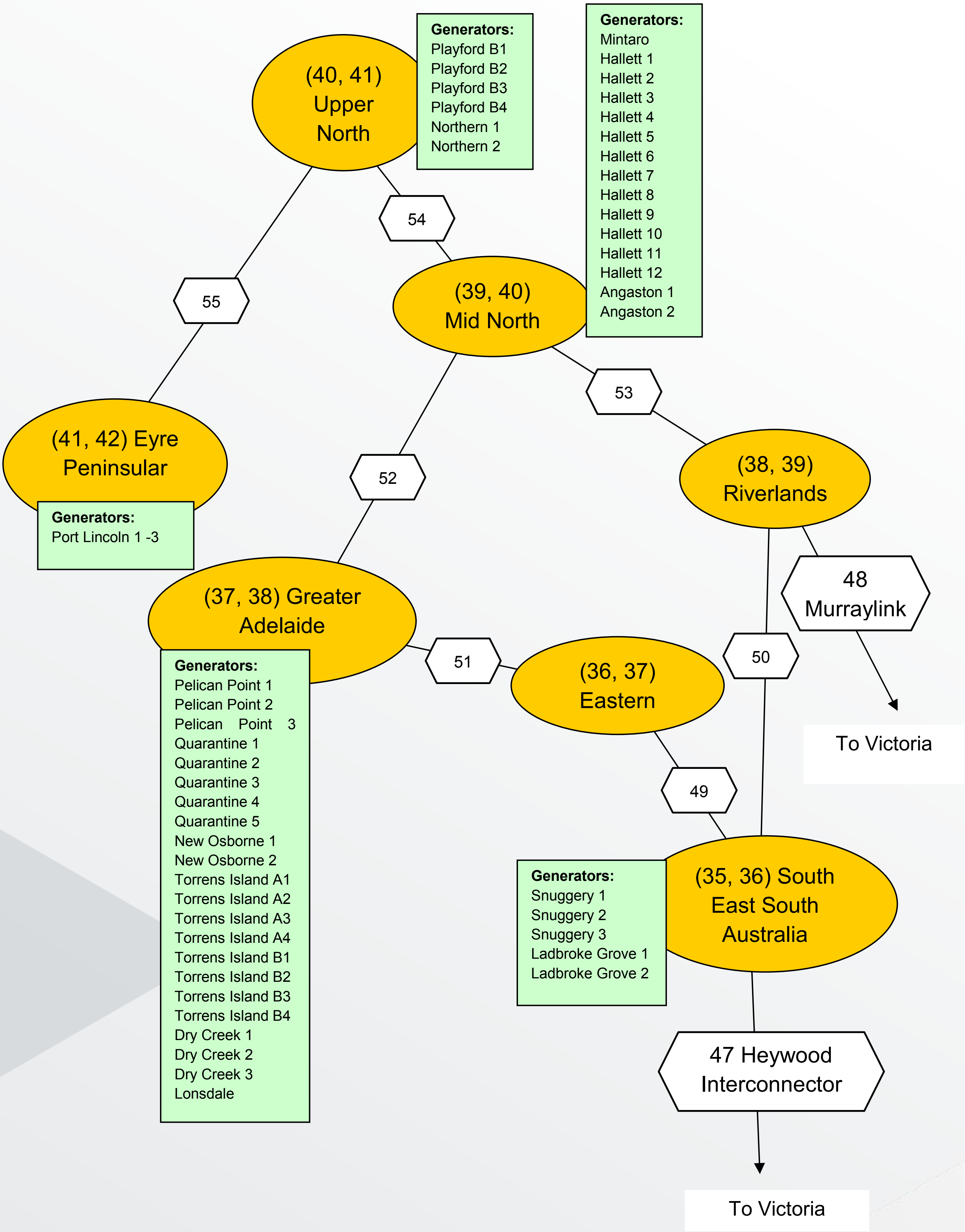
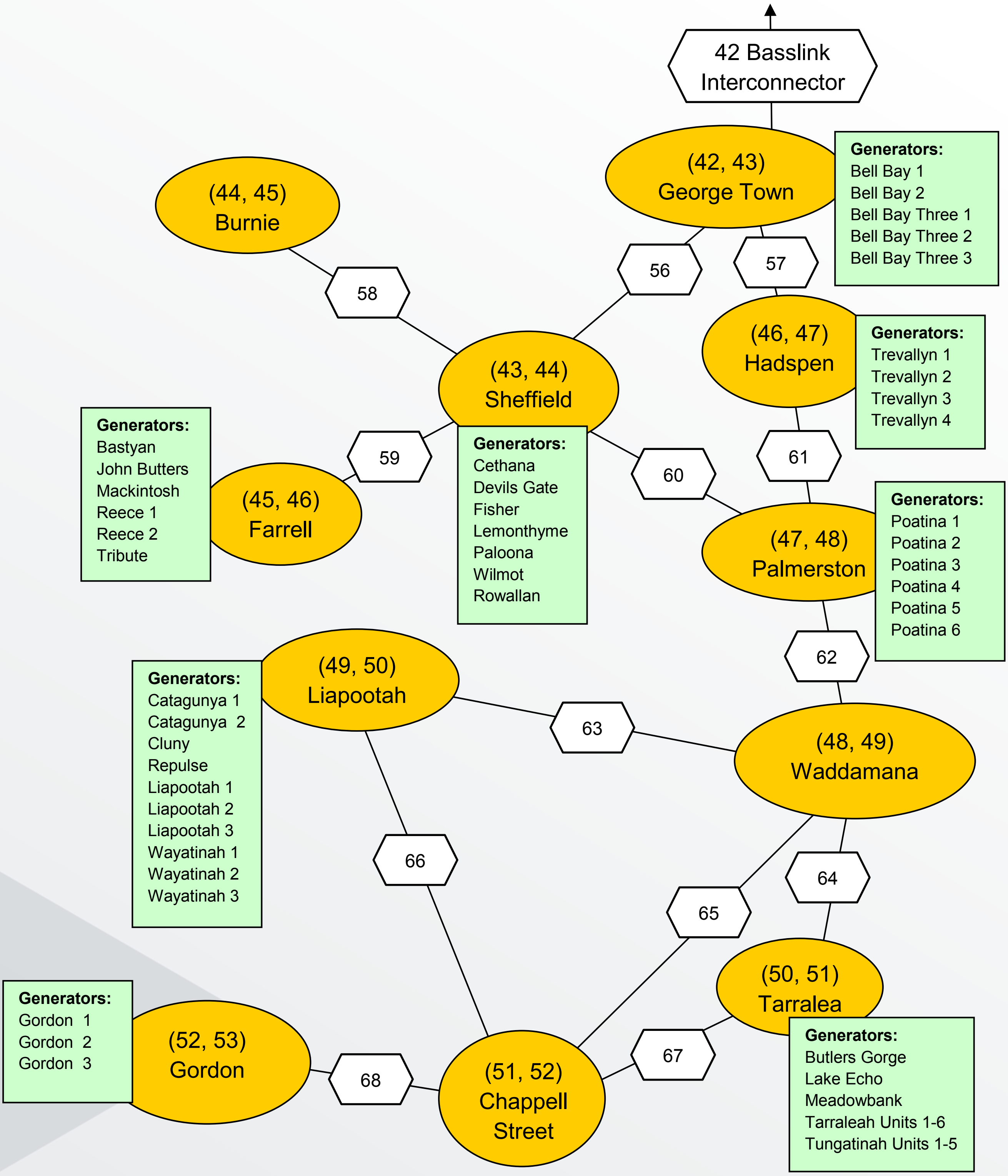


**Figure 19: Stylised topology of TAS transmission lines and Load Serving Entities**



# 9 Appendix B – Australian National Electricity Market Model

This appendix discusses the Australian National Electricity Market (ANEM) Model. This report uses the ANEM model to study the interactions between the NEM and the proposed plant at Collinsville to determine:

- Wholesale spot price; and
- Dispatch.

The ANEM model uses the node and transmission line topology in Appendix A. ANEM is an agent based model and the agents include demand and supply side participants as well as a network operator. The behaviour of these agents is constrained by the transmission grid whose network configuration is defined by the nodes and transmission lines shown in Appendix B. The following sections provide an outline of the ANEM model and present the principal features of the agents in the model. The ANEM's algorithm used to calculate generation production levels, wholesale prices and power flows on transmission lines is discussed. Finally, practical implementation considerations are discussed.

## 9.1 Outline of ANEM model

The methodology underpinning the ANEM model involves the operation of wholesale power markets by an Independent System Operator (ISO) using Locational Marginal Pricing (LMP) to price energy by the location of its injection into, or withdrawal from, the transmission grid. ANEM is a modified and extended version of the American *Agent-Based Modelling of Electricity Systems* (AMES) model developed by Sun and Tesfatsion (2007a, 2007b) and utilises the emerging powerful computational tools associated with Agent-based Computational Economics (ACE). This type of modelling is built upon a realistic representation of the network structure under consideration with high frequency behavioural interactions that are made possible by the availability of powerful computing resources. The important differences between the institutional structures of the Australian and USA wholesale electricity markets are also fully reflected in the modelling undertaken and outlined more fully in Wild, Bell and Foster (2012, Sec. 1).

To understand the interaction between the proposed plant and the NEM requires a realistic model containing many of the salient features of the NEM. These features include realistic transmission network pathways, competitive dispatch of all generation technologies with price determination based upon variable cost and branch congestion characteristics and intra-regional and inter-state trade.

In the ANEM model, a Direct Current Optimal Power Flow (DC OPF) algorithm is used to determine optimal dispatch of generation plant, power flows on transmission branches and wholesale prices. This framework accommodates many of the features mentioned above including: intra-state and inter-state power flows; regional location of generators and load centres; demand bid information and the following unit commitment features:

- variable generation costs;
- thermal Megawatt (MW) limits (applied to both generators and transmission lines);
- generator ramping constraints;
- generator start-up costs; and
- generator minimum stable operating levels.

## 9.2 Principal features of the ANEM model

The ANEM model is programmed in Java using Repast (2014), a Java-based toolkit designed specifically for agent base modelling in the social sciences. The core elements of the model are:

- The wholesale power market includes an ISO and energy traders that include demand side agents called Load-Serving Entities (LSE's) and generators distributed across the nodes of the transmission grid.
- The transmission grid is an alternating current (AC) grid modelled as a balanced three-phase network.
- The ANEM wholesale power market operates using increments of one half-hour.
- The ANEM model ISO undertakes daily operation of the transmission grid within a single settlement system, which consists of a real time market settled using LMP.
- For each half-hour of the day, the ANEM model's ISO determines power commitments and LMP's for the spot market based on generators' supply offers and LSE's demand bids which are used to settle financially binding contracts.
- Transmission grid congestion in the spot market is managed via the inclusion of congestion components in the LMP.

### 9.2.1 Transmission grid characteristics in the ANEM model

The transmission grid utilised in the ANEM model is an AC grid modelled as a balanced three-phase network. In common with the design features outlined in Sun and Tesfatsion (2007a), we make the following additional assumptions:

- The reactance on each branch is assumed to be a total branch reactance, meaning that branch length has been taken into account in determining reactance values;
- All transformer phase angle shifts are assumed to be 0;
- All transformer tap ratios are assumed to be 1; and
- All line-charging capacitances are assumed to be 0.

To implement the DC OPF framework used in the ANEM model, two additional electrical concepts are required. These are base apparent power which is measured in three-phase Megavoltamperes (MVA's), and base voltage which is measured in line-to-line Kilovolts (kV's). These quantities are used to derive the conventional per unit (PU) normalisations used in the DC OPF solution and facilitate conversion between Standard International (SI) and PU unit conventions.

The transmission grid can be viewed as a commercial network consisting of pricing locations for the purchase and sale of electricity power. A pricing location is also a location at which market transactions are settled using publicly available LMP's and coincides with the set of transmission grid nodes.

The transmission grid in the ANEM model contains 68 branches and 52 nodes and is outlined in Appendix A.  It combines the Queensland (QLD), New South Wales (NSW), Victorian (VIC), South Australia (SA) and Tasmanian (TAS) state modules. The state module linking is via the following inter-state Interconnectors: QNI (line 11) and Directlink (line 14) linking Queensland and New South Wales; Tumut-Murray (line 35), Tumut-Dederang (line

36) and Tumut-Regional Victoria (line 37) linking New South Wales and Victoria; Heywood (line 47) and MurrayLink (line 48) linking Victoria and South Australia; and Basslink (line 42) linking Victoria and Tasmania. In accordance with the DC OPF framework utilized in the model, the High Voltage DC (HVDC) Interconnectors Directlink, Murraylink and Basslink are modelled as 'quasi AC' links with power flows being determined by reactance and thermal MW rating values only.

The major power flow pathways in the model reflect the major transmission pathways associated with 275, 330, 500/330/220, 275 and 220 KV transmission branches in Queensland, New South Wales, Victoria, South Australia and Tasmania, respectively. Key transmission data required for the transmission grid in the model relate to an assumed base voltage value, base apparent power, branch connection and direction of flow information, maximum thermal rating of each transmission branch (in MW's) and an estimate of its reactance value (in ohms). Base apparent power is set to 100 MVA, an internationally recognized value. Thermal ratings of transmission lines was constructed from data contained in AEMO (2013c) using the detailed grid diagrams in AEMO (2013b) to identify transmission infrastructure relevant to the transmission grid structure used in the ANEM model. Reactance data was obtained from AEMO load flow data provided to the authors on a confidential basis.

It should be noted that these latter values were defined in the AEMO files in terms of MVA values. We convert these values to MWs assuming a power factor of unity. As such, the MW values used in the modelling correspond exactly to the MVA values listed in the source AEMO data files. We also utilize information in the AEMO equipment ratings files to accommodate differences in maximum thermal ratings between summer and winter. Typically, the maximum MW thermal capacity rating of transmission lines is greater in magnitude in winter than in summer because of the lower temperatures occurring in winter when compared to summer. Our modelling takes explicit account of this by using different thermal MW capacity values in summer and winter. We also assume that reactance is unaffected by temperature, but instead, are primarily determined by the alloy used in the transmission lines' conductors. This assumption permits the use of a constant value for the reactance on each branch with this data sourced from confidentially provided AEMO network snapshot data.

In Appendix A, the direction of flow on a transmission branch (e.g. line) connecting two nodes is defined as a 'positive' flow if the power flows from the lower numbered node to the higher numbered node. For example, for line 1 connecting Far North Queensland (node 1) and the Ross node (node 2), power flowing from Far North Queensland to Ross on line 1 would have a positive sign while power flowing on line 1 from Ross to Far North Queensland would have a negative sign. The latter type of power flow is termed 'reverse' direction flow. In the ANEM model, it is possible to accommodate power flows in the positive and reverse direction having different thermal limits as well as also varying in magnitude between summer and winter.

### 9.2.2 Demand-side agents in the ANEM model: LSE's

A LSE is an electric utility that has an obligation to provide electrical power to end-use consumers (residential, commercial or industrial). The LSE agents purchase bulk power in the wholesale power market each day to service customer demand (called load) in the downstream retail market, thereby linking the wholesale power market and retail market. We assume that downstream retail demands serviced by the LSE's exhibit negligible price sensitivity, reducing to daily supplied load profiles which represents the real power demand (in MW's) that the LSE has to service in its downstream retail market for each half-hour of the day. LSE's are also modelled as passive entities who submit daily load profiles to the ISO without strategic considerations (Sun & Tesfatsion 2007b).

The revenue received by LSE's for servicing these load obligations are regulated to be a simple 'dollar mark-up' based retail tariff. For example, in Queensland, the state government regulates retail tariffs that are payable by most residential customers. Prior to July 2009, for example, this amounted to 14.4c/KWh (excl GST) which, in turn, translated into a retail tariff of $144/MWh. Thus, in the current set-up, LSE's are assumed to have no incentive to submit price-sensitive demand bids into the market.

The half-hourly regional load data for Queensland and New South Wales required by the model was derived using regional load traces supplied by Powerlink and Transgrid. This data was then re-based to the state load totals published by AEMO (2014b) for the 'QLD1' and 'NSW1' markets. For the other three states, the regional shares were determined from terminal station load forecasts associated with summer peak demand (and winter peak demand, if available) contained in the annual planning reports published by the transmission companies Transend (Tasmania), Vencorp (Victoria) and ElectraNet (South Australia). These regional load shares were then interpolated to a monthly based time series using a cubic spline technique and these time series of monthly shares were then multiplied by the 'TAS1', 'VIC1' and 'SA1' state load time series published by AEMO (2014b) in order to derive the regional load profiles for Tasmania, Victoria and South Australia.

It should be recognised that the demand concept underpinning the state totals published by AEMO and used in the modelling is a net demand concept related conceptually to the output of scheduled and semi-scheduled generation, transmission losses and large independent loads directly connected to the transmission grid. This demand concept is termed 'scheduled demand' (AEMO 2012a). As such, this net demand concept can be viewed as being calculated from gross demand, after contributions from small scale solar PV and both small scale and large scale non-scheduled generation (including wind, hydro and bagasse generation) has been netted out to produce the net demand concept used in the modelling.

The actual demand concept employed in the modelling is a grossed up form of scheduled demand which was obtained by adding the output of large-scale non-scheduled generation to the scheduled demand data, see Equation 1. Five minute non-scheduled generation output data for the period 2007 to 2012 was obtained from AEMO and averaged across six five minute intervals to obtain half-hourly output traces. This data was then summed across all non-scheduled generators located within a node and added to the nodal based scheduled demand to determine the nodal based augmented demand concept used in the modelling. Therefore, the demand concept employed in the modelling equates to the sum of the output of scheduled and semi-scheduled generation, non-scheduled generation, transmission losses and large independent loads directly connected to the transmission grid. It does not include the contributions from small scale solar PV and WTG and, as such, still represents a net demand concept.

### 9.2.3 Supply-side agents in the ANEM model: generators

Generators are assumed to produce and sell electrical power in bulk at the wholesale level. Each generator agent is configured with a production technology with assumed attributes relating to feasible production interval, total cost function, total variable cost function, fixed costs [pro-rated to a dollar per hour basis] and a marginal cost function. Depending upon plant type, a generator may also have start-up costs. Each generator also faces MW ramping constraints that determine the extent to which real power production levels can be increased or decreased over the next half-hour within the half hourly dispatch horizon. Production levels determined from the ramp up and ramp down constraints must fall within the minimum and maximum thermal MW capacity limits confronting each generator.

The MW production and ramping constraints are defined in terms of 'energy sent out' – i.e. the energy available to service demand. In contrast, variable costs and carbon emissions are calculated from the 'energy generated' production concept which is defined to include energy sent out plus a typically small amount of additional energy that is produced internally as part of the power production process. The variable costs of each generator are modelled as a quadratic function of half-hourly real energy produced by each generator. The marginal cost function is calculated as the partial derivative of the quadratic variable cost function with respect to hourly energy produced, producing a marginal cost function that is linear (upward sloping) in real energy production of each generator (Sun & Tesfatsion 2007b).

The variable cost concept underpinning each generator's variable cost incorporates fuel, variable operation and maintenance (VO&M) costs and carbon cost components. The fuel, VO&M and carbon emissions/cost parameterisation was determined using data published in ACIL Tasman (2009) for thermal plant and from information sourced from hydro generation companies for hydro generation units. Wild, Bell and Foster (2012, App. A) provide a formal derivation of the various cost components in greater detail.

### 9.2.4 Passive hedging strategy incorporated in the ANEM model

Both theory and observation suggest that financial settlements based on market structures similar to that implemented in the NEM expose market participants to the possibility of extreme volatility in spot prices encompassing price spike behaviour (typically of short duration) or sustained periods of low spot prices. These impacts pose significant danger to the bottom line of both LSE's and generators respectively, requiring both types of agents to have long hedge cover positions to protect their financial viability.

In the ANEM model, a key decision for both types of agents is when to activate long cover to protect their bottom lines from the consequences of consistently high (low) spot prices – key determinants of 'excessively' high costs ('excessively' low revenues) faced by LSE's and generators, respectively. Failure to do so could pose serious problems for the continued financial solvency of market participants. The form of protection adopted in the model is a 'collar' instrument between LSE's and generators which is activated whenever spot prices rise above a ceiling price (for LSE's) or falls below a price floor (for generators). If the price floor applicable to generators is set equal to the generators long run marginal cost than generator long run revenue recovery can be implemented through the hedge instrument.

It is assumed that both LSE's and generators pay a small fee (per MWh of energy demanded or supplied) for this long hedge cover, irrespective of whether long cover is actually activated. Thus, the small fee acts like a conventional premium payment in real options theory. If the spot price is greater than the price floor applicable to generator long cover and below the price ceiling applicable for LSE long cover, than no long cover is activated by either type of agent although the fee payable for the long cover is still paid by both types of agents.

## 9.3 DC OPF solution algorithm used in the ANEM model

Optimal dispatch, wholesale prices and power flows on transmission lines are determined in the ANEM model by a DC OPF algorithm. The DC OPF algorithm utilised in the model is that developed in Sun and Tesfatsion (2007a) and involves representing the standard DC OPF problem as an augmented strictly convex quadratic programming (SCQP) problem, involving the minimization of a positive definite quadratic form subject to linear equality and inequality constraints. The augmentation entails utilising an objective function that contains quadratic and linear variable cost coefficients and branch connection and bus admittance coefficients. The solution values are the real power injections and branch flows associated with the energy production levels for each generator and voltage angles for each node.

We use Mosek (2014) optimisation software that exploits direct sparse matrix methods and utilises a convex quadratic programming algorithm based on the interior point algorithm to solve the DC OPF problem. Equation 5 shows ANEM's implementation of the Mosek DC OPF algorithm inequality constraints.

The ANEM model solves the following optimisation for every half-hour. Equation 5(a) shows the objective function that minimises real-power production levels $P_{Gi}$ for all generators $i = 1,...,I$ and voltage angles $\delta_k$ for all transmission lines and $k = 2,..,K$ subject to the constraints in Equation 5(b), (c) and (d).

**Equation 5: ANEM's objective function and constraints**

**(a) Objective function: Minimise generator-reported total variable cost and nodal angle differences**

$$\sum_{i=1}^{I}\left[A_i P_{G_i} + B_i P_{G_i}^2\right] + \pi\left[\sum_{I_m \in BR}\delta_m^2 + \sum_{km \in BR,\, k\geq 2}[\delta_k - \delta_m]^2\right],$$

Where:

$i$ = generator number
$P_{Gi}$ = real power (MW) production level of generator $i$
$k$ = transmission line number
$\delta_k$ = phase angle for transmission line $k$

**(b) Constraint 1: Nodal real power balance equality constraint; k = 1,⋯,K with δ 1≡ 0:**

$$0 = PLoad_k - PGen_k + PNetInject_k \text{ ,}$$

Where:

$PLoad_k = \sum_{j \in J_k} P_{L_j}$ (e.g. aggregate power take-off at node k),

$PGen_k = \sum_{i \in I_k} P_{G_i}$ (e.g. aggregate power injection at node k),

$PNetInject_k = \sum_{km \text{ or } mk \in BR} F_{km}$

$F_{km} = B_{km}\left[\delta_k - \delta_m\right]$

(e.g. real power flows on branches connecting nodes 'k' and 'm').

**(c) Constraint 2: Transmission line real power thermal inequality constraints; $km \in BR;\ k = 1, \ldots, K$ with $\delta_1 \equiv 0$**

$F_{km} \geq -F_{km}^{UR}$, (lower bound constraint: reverse direction MW branch flow limit)

$F_{km} \leq F_{km}^{UN}$, (upper bound constraint: normal direction MW branch flow limit).

**(d) Constraint 3: Generator real-power production inequality constraints; i = 1, ,I**

$P_{G_i} \geq P_{G_i}^{LR}$, (lower bound constraint: lower half-hourly MW thermal ramping limit)

$P_{G_i} \leq P_{G_i}^{UR}$ (upper bound constraint: upper half-hourly MW thermal ramping limit),

Where:

$P_{G_i}^{LR} \geq P_{G_i}^{L}$,

(lower half-hourly thermal ramping limit ≥ lower thermal MW capacity limit)

$P_{G_i}^{UR} \leq P_{G_i}^{U}$

(upper half-hourly thermal ramping limit ≤ upper thermal MW capacity limit).

Upper limit $U$ and lower limit $L$, $A_i$ and $B_i$ are linear and quadratic cost coefficients from the variable cost function. $\delta_k$ and $\delta_l$ are the voltage angles at nodes '*k*' and '*m*' (measured in radians). Parameter $\pi$ is a positive soft penalty weight on the sum of squared voltage angle differences. Variables $F^{UN}{}_{km}$ and $F^{UR}{}_{km}$ are the (positive) MW thermal limits associated with real power flows in the 'normal' and 'reverse' direction on each connected transmission branch $km \in BR$.

The linear equality constraint refers to a nodal balance condition which requires that, at each node, power take-off (by LSE's located at that node) equals power injection (by generators located at that node) and net power transfers from other nodes on 'connected' transmission branches. On a node by node basis, the shadow price associated with this constraint gives the LMP (i.e. regional wholesale spot price) associated with that node. The linear inequality constraints ensure that real power transfers on connected transmission branches remain within permitted 'normal' and 'reverse' direction thermal limits and the real power produced by each generator remains within permitted lower and upper thermal MW capacity limits while also meeting MW ramp up and ramp down generator production limits.

The ANEM model differs in significant ways from many of the wholesale electricity market models used to investigate the Australian electricity industry. First, the nodal structure of the ANEM model is more disaggregated than the structure underpinning many of the other wholesale market models. Depending upon the treatment of Snowy Mountains Region in the NEM, the grid structures associated with wholesale market models used previously often involve five or six nodes (corresponding to each state region in the NEM) and six or seven inter-state interconnectors – see McLennan Magasanik Associates (MMA 2006), ROAM Consulting (ROAM 2008, App. A, p. II), Sinclair Knight Merz (SKM & MMA 2011, p. 62) and ACIL Tasman (2011, Sec. B.2). In contrast, the ANEM model contains 52 nodes and 68 transmission branches, including eight inter-state interconnectors and 60 intra-state transmission branches as depicted in Appendix B.

Second, the solution algorithm used in the ANEM model is very different conceptually from the linear programming algorithms used in many of the other wholesale market models. In the ANEM model, quadratic programming is employed to minimise both nodal angle differences and generator variable costs subject to network limits on transmission branches and generation. Optimal power flows on transmission branches are determined from optimised nodal angle differences, which, in turn, depend on transmission branch adjacency and bus admittance properties determined from the transmission grid's structure and branch reactance data (Sun & Tesfatsion 2007a, Sec. 4). Accounting for power flows in the equality constraints of the DC OPF algorithm allows the incorporation of congestion components in regional wholesale spot prices, which can produce divergence in regional spot prices associated with congestion on intra-state transmission branches.

In contrast, the linear programming algorithms do not explicitly optimise power flows as part of the optimisation process, directly capture the impact of branch congestion on spot prices or account for any impact associated with congestion on intra-state transmission branches. Moreover, intra-state regional spot prices are not typically defined in these models.

## 9.4 Practical implementation considerations

The solution algorithm employed in all simulations involves applying the 'competitive equilibrium' solution. This means that all generators submit their true marginal cost coefficients and no strategic bidding is allowed, permitting assessment of the true cost of generation and dispatch. We also assume that all thermal generators are available to supply power during the whole period under investigation. This rules out the possibility where allowing for planned or unscheduled outages in thermal generators would be expected to increase costs and prices above what is produced when all thermal plant is assumed to be available to supply power because it acts to constrain the least cost supply response available to meet prevailing demand.

Therefore, the methodological approach underpinning modelling is to produce 'as if' scenarios. In particular, we do not try to emulate actual generator bidding patterns for the years in question. Our objective is to investigate, in an ideal setting, how the proposed plant at Collinsville would interact with the NEM, from the perspective of least-cost dispatch.

In order to make the model response to the various scenarios more realistic, we have taken account of the fact that baseload and intermediate coal and gas plant typically have 'non-zero' must run MW capacity levels termed minimum stable operating levels. These plants cannot be run below these specified MW capacity levels without endangering the long term productive and operational viability of the plant itself or violating statutory limitations relating to the production of pollutants and other toxic substances.

Because of the significant run-up time needed to go from start-up to a position where coal-fired power stations can actually begin supplying power to the grid, all coal plant was assumed to be synchronized with the grid so they can supply power. Thus, their minimum stable operating limits were assumed to be applicable for the whole period being investigated and they do not face start-up costs. Gas plant, however, has very quick start-up characteristics and can be synchronized with the grid and be ready to supply power typically within a half hour period of the decision to start-up. Therefore, in this case, the start-up decision and fixed start-up costs can accrue within the dispatch period being investigated.

Two approaches to modelling gas plant were adopted depending upon whether the gas plant could reasonably be expected to meet baseload or intermediate production duties or just peak load duties. If the gas plant was capable of meeting baseload or intermediate production duties, the plant was assigned a non-zero minimum stable operating capacity. In contrast, peak gas plant was assumed to have a zero minimum stable operating capacity. Furthermore, if the baseload/intermediate gas plant was a gas thermal or Natural Gas Combined Cycle (NGCC) plant, it was assumed to offer to supply power for a complete 24 hour period – thus, the minimum stable operating capacity was applicable for the whole 24 hour period and these plants did not face start-up costs. In contrast, many of the intermediate Open Cycle Gas Turbine (OCGT) plant were assumed to only offer to supply power during the day. In this case, the minimum stable operating capacities were only applicable for those particular half-hours of the day and these plants faced the payment of fixed start-up costs upon start-up.

Details of the minimum stable operating capacities assumed for coal and intermediate gas plant are listed in Table 14 and Table 15, together with details about their assumed operating time, whether start-up costs were liable and, if so, what values were assumed for these particular costs.

**Table 14: Minimum stable operating capacity limits for coal plant, assumed operating time and start-up cost status**

| Generation Plant | Minimum Stable Operating Capacity Level<br>% of total MW Capacity (sent out basis) | Assumed Operating Time<br>Hours | Start-up Status/Cost<br>Yes/No | Assumed Start-up Cost<br>$/MW per start |
|---|---|---|---|---|
| **Black Coal – QLD** | | | | |
| Collinsville | 40.00 | 24 | No | $160.00 |
| Stanwell | 40.00 | 24 | No | $ 80.00 |
| Callide B | 40.00 | 24 | No | $ 80.00 |
| Callide C | 40.00 | 24 | No | $ 80.00 |
| Gladstone | 31.00 | 24 | No | $ 90.00 |
| Tarong North | 40.00 | 24 | No | $ 70.00 |
| Tarong | 40.00 | 24 | No | $ 80.00 |
| Kogan Creek | 40.00 | 24 | No | $ 40.00 |
| Millmerran | 40.00 | 24 | No | $ 70.00 |
| Swanbank B | 26.00 | 24 | No | $150.00 |
| **Black Coal – NSW** | | | | |
| Liddle | 40.00 | 24 | No | $ 50.00 |
| Redbank | 40.00 | 24 | No | $150.00 |
| Bayswater | 40.00 | 24 | No | $ 45.00 |
| Eraring | 40.00 | 24 | No | $ 45.00 |
| Munmorrah | 40.00 | 24 | No | $ 80.00 |
| Vales Point | 40.00 | 24 | No | $ 45.00 |
| Mt Piper | 40.00 | 24 | No | $ 45.00 |
| Wallerawang | 40.00 | 24 | No | $ 50.00 |
| **Black Coal – SA** | | | | |
| Playford B | 40.00 | 24 | No | $150.00 |
| Northern | 55.00 | 24 | No | $ 90.00 |
| **Brown Coal – VIC** | | | | |
| Loy Yang A | 60.00 | 24 | No | $ 50.00 |
| Loy Yang B | 60.00 | 24 | No | $ 50.00 |
| Energy Brix | 60.00 | 24 | No | $160.00 |
| Hazelwood | 60.00 | 24 | No | $ 95.00 |
| Yallourn | 60.00 | 24 | No | $ 80.00 |
| Anglesea | 60.00 | 24 | No | $150.00 |

**Table 15: Minimum stable operating capacity limits for baseload and intermediate gas plant, assumed operating time and start-up cost status**

| Generation Plant | Minimum Stable Operating Capacity Level<br>% of total MW Capacity (sent out basis) | Assumed Operating Time<br><br>Hours | Start-up Status/Cost<br><br>Yes/No | Assumed Start-up Cost<br><br>$/MW per start |
|---|---|---|---|---|
| **QLD** | | | | |
| Townsville | 50.00 | 24 | No | $100.00 |
| Braemar 1 | 50.00 | 13 daytime only | Yes | $100.00 |
| Braemar 2 | 50.00 | 13 daytime only | Yes | $100.00 |
| Condamine | 50.00 | 24 | No | $50.00 |
| Darling Downs | 50.00 | 24 | No | $50.00 |
| Swanbank E | 50.00 | 24 | No | $ 50.00 |
| **NSW** | | | | |
| Smithfield | 60.00 | 24 | No | $100.00 |
| Uranquinty | 50.00 | 13 daytime only | Yes | $ 90.00 |
| Tallawarra | 50.00 | 24 | No | $ 40.00 |
| **VIC** | | | | |
| Newport | 65.00 | 13 daytime only | Yes | $ 40.00 |
| **SA** | | | | |
| Ladbroke Grove | 50.00 | 13 daytime only | Yes | $110.00 |
| Pelican Point | 50.00 | 24 | No | $ 70.00 |
| New Osborne | 76.00 | 24 | No | $ 80.00 |
| Torrens Is. A | 50.00 | 13 daytime only | Yes | $ 80.00 |
| Torrens Is. B | 50.00 | 24 | No | $ 65.00 |

It should be noted that there was some commissioning and de-commissioning of thermal generation plant during the period under investigation which was accommodated in the modelling. Specifically, the following plant was commissioned:

- Condamine, unit 3 in 2010-11;
- Darling Downs, all units in 2010-11;
- Yarwun in 2010-11; and
- Mortlake, all units in 2011-12.

The following generation was assumed to be de-commissioned:

- Swanbank B:
  - two units in 2010-11;
  - one unit in 2011-12;
  - last unit in 2012-13;
- Collinsville, all units in 2012-13;
- Munmorah, all units in 2012-13;
- Energy Brix, units 3-5 in 2012-13;
- Energy Brix, units 1-2 in 2013-14;
- Playford B, all units in 2012-13; and
- Wallerarang C, all units from 2014.

While we have accommodated the permanent plant closures listed above (including Playford B which we have assumed will not be operated again because of its age), we have also included some recently announced temporary plant closures associated with:

- Tarong, units 3 and 4 in 2012-13;

- Wallerarang C, one unit in 2012-13 with permanent closure of the whole plant from 2014;
- Swanbank E, in 2014-2016;
- Yallourn, winter 2012 and 2013;
- Northern, winter 2012, 2013 and one unit in 2014.

We have also fixed the generation structure used in simulations for the period 2009-10 to 2030-31 to the structure listed in Appendix A. In particular, we did not attempt to include any future proposed projects in the analysis because there is currently too much uncertainty over both the status and timing of many proposed projects. This uncertainty principally reflects three factors. The first relates to financial uncertainty over future gas prices once the eastern seaboard CSG/LNG projects begin to operate from 2014-15. The second factor relates to the fall in average demand experienced widely throughout the NEM over the last couple of years, which affects the viability of baseload generation proposals as well as the future commissioning date of new project proposals. Specifically, the medium AEMO (2013a) reserve deficit projection is zero until 2022-23 with the exception of Queensland at 159MW in 2019-20. This implies an oversupply of generation capacity to meet demand, requiring no investment in new thermal plant until at least 2022-23. The third source of uncertainty is regulatory and political uncertainty about the future of both the recently implemented carbon tax scheme and renewable energy certificate scheme, which affects the financial viability of gas and renewable generation project proposals, in particular. Therefore, given the generation set available for the ANEM model simulations, our modelling focuses on the interaction of the Collinsville plant with NEM, in particular the wholesale spot price.

While all thermal generators were assumed available to supply power, certain assumptions were imposed in relation to the availability of hydro generation units. The dispatch of thermal plant was optimised around the assumed availability patterns for the hydro generation units. In determining the availability patterns for hydro plant, we assumed that water supply for hydro plant was not an issue. If water supply issues or hydro unit availability were constraining factors, as was actually the case in 2007, for example, this would increase the cost and prices obtained from simulations because the cost of supply offers of hydro plant would be expected to increase significantly.

Because of the prominence of hydro generation in Tasmania, some hydro units were assumed to offer capacity over the whole year with account being taken of the ability of hydro plant to meet base load, intermediate or peak load production duties. For pump-storage hydro units such as Wivenhoe and Shoalhaven, the pump mode was activated by setting up a pseudo LSE located at the Morton North and Wollongong nodes – see Section 8 for further details. The combined load requirements for pump actions of all Wivenhoe and Shoalhaven hydro units were combined into a single load block determined by the model from unit dispatch records of these generators from the previous day and placed in the relevant pseudo LSE's. In both cases, the pump actions are assumed to occur in off-peak periods when the price (cost to hydro units) of electricity is lowest.

For all hydro plant, hydro generator supply offers were based on long run marginal cost coefficients. These coefficients take into account the need to meet fixed costs including capital and operational expenses and are often significantly larger in magnitude than corresponding short run marginal cost coefficients. For mainland hydro plant, supply was tailored to peak load production. Thus, long run marginal cost estimates were obtained for much lower annual capacity factors (ACF) than would be associated with hydro plant fulfilling base load or intermediate production duties, thus producing higher long run marginal cost coefficients. Moreover, the ACF was reduced for each successive hydro turbine making up a hydro plant resulting in an escalating series of marginal cost coefficient bids for each successive turbine. In general, the lowest marginal cost coefficient shadowed peak load OCGT plant while other turbines supply offers could be significantly in excess of cost coefficients associated with more expensive peak load gas or diesel plant. This approach essentially priced the social cost of water usage within successive turbines of a hydro plant as an increasingly scarce commodity.

A key consideration governing the decision to use long run marginal cost coefficients to underpin the supply offers of hydro generation plant is the predominance of such generators in Tasmania. With the absence of other major forms of thermal based generation in Tasmania and limited native load demand and export capability into Victoria, it is likely that nodal pricing, based on short run marginal costs, would not be sufficient to cover operational and capital costs. Supply offers based on long run marginal costs, however, ensure that average price levels are sufficient to cover these costs over the lifetime of a hydro plant's operation. We also assumed that the minimum stable operating capacity for all hydro plant is zero and that no start-up costs are incurred when the hydro plants begin supplying power to the grid. Hydro plant is also assumed to have a very fast ramping capability.

Non-scheduled and semi-scheduled WTG are also included in the modelling, incorporating thirteen non-scheduled and thirteen semi-scheduled wind farms with a combined capacity of 2471.8 MW, which represents 96.8 per cent of total installed capacity of operational wind farms in the NEM at the end of 2012. Wind farms are assumed to construct supply offers for their output based upon their variable costs. As such, they are assumed to operate essentially as semi-scheduled plant. We assume that 85 per cent of total operating costs of wind farms are fixed costs whilst the remaining 15 per cent are variable costs. In general, the ($/MWh) supply offers of wind farms used in the modelling was in the range of $3.39/MWh to $4.69/MWh, and are amongst the cheapest forms of generation incorporated in the modelling.

Both non-scheduled and semi-scheduled wind generation operational over the period 2007 to 2012 was incorporated in the modelling. However, the output of the wind farms in the modelling are incorporated as aggregated nodal wide entities calculated by summing the output of all non-scheduled and semi-scheduled wind farms located within a particular node. Moreover, we are restricting attention to those nodes that contain operating wind farms.

The default setting adopted for modelling purposes is for wind generation not to be dispatched with supply offers set to '*Value Of Lost Load*' (VOLL) which is set to $10000/MWh. This default setting is overridden when the output of the nodal based wind generation source exceeds 10MW with supply offers then being based on short run marginal cost coefficients.

In the ANEM model simulations performed for this project, we have also adopted an 'n' transmission configuration scenario. This approach involves applying the MW thermal limits determined from the sum of all individual transmission line thermal ratings in the group of transmission lines connecting two nodes. This approach effectively assumes no line outages occur and that the transmission lines are all in good working condition. For example, the capacity of each line is unconstrained below its rated capacity when all other transmission lines are operating at their maximum capacity. As such, this approach represents, from the perspective of operational constraints of the transmission network, an ideal setting, matching the approach we also adopted in relation to thermal and hydro generation unit availability.

The approach adopted in this project can be contrasted with the more realistic 'n-1' transmission configuration scenario which typically involves subtracting the largest individual line from the group connecting nodes. This latter approach is linked to reliability considerations that ensure that things do not go ‘pear shaped’ if the largest single line is lost, and as such, is a more realistic operational setting.

The main reason we adopted the ‘n’ transmission configuration scenario was because of the length of the time interval involved with the project which goes out to 2040. As such, we are sacrificing some operational realism in the near turn but also recognising that the current ‘n’ scenario might well become an ‘n-1’ scenario towards the end of the simulation time horizon if additional transmission lines were to be added.

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T: (+61 7) 3443 3100 / E: gci@uq.edu.au
Global Change Institute Building (Bldg. 20)
Staff House Road
University of Queensland
St Lucia QLD 4072, Australia

**www.gci.uq.edu.au**